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S. HRG. 102-5 (Pt. 15)

NATIONAL ENERGY SECURITY ACT OF 1991

(Appendixes to Parts 5, 6 and 7)

HEARINGS

BEFORE THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

ONE HUNDRED SECOND CONGRESS

FIRST SESSION

ON

Appendixes to S. 341

PERTAINING TO

Part 5

TITLES XII AND XIII (MAR. 5)

Part 6

SECTIONS 6003 AND 6004 OF TITLE VI AND TITLE X (MAR. 7)

Part 7

TITLES VII AND VIII (MAR. 11)

PART 15

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(Titles XII and XIII)

Appendix I—Responses to Additional Questions

POST-HEARING QUESTIONS AND ANSWERS

WILLIAM H. YOUNG
ASSISTANT SECRETARY FOR NUCLEAR ENERGY
U.S. DEPARTMENT OF ENERGY

MARCH 5, 1991

QUESTION FROM SENATOR WALLOP

ELECTRICITY SUPPLY

Question 1. The Department of Energy estimates that a combination of increases in demand and retirement of existing electric generation capacity will require an additional 200,000 megawatts of capacity by the year 2010.

a. Would you agree with Mr. Wolfe's statement that until recently there has been considerable excess electrical capacity in this country but this era is coming to an end?

Answer: Some regions of the U.S. had excess generating capacity through the 1980's. However, during the late 1980's, some regions -- notably New England -- had limited capacity reserves and experienced occasional degradation in service because of insufficient generating capacity.

We expect regions that still have excess capacity to need new capacity by the mid or late 1990's. The era of excess capacity is coming to an end, but there is substantial variance from region to region.

b. Faced with today's environmental laws such as the Clean Air Act, in your judgement, can this requirement for new generation capacity be satisfied without a greater role for nuclear power than is possible under present circumstances?

Answer: Theoretically, the requirement for new generating capacity could be satisfied without additional nuclear capacity, even with passage of the Clean Air Act. A combination of conservation, natural gas, renewables, and innovative clean coal technologies that emit low levels of sulfur dioxide and nitrous oxides could meet our Nation's future electricity requirements and satisfy the requirements of the Clean Air Act.

However, without nuclear power as an option, we would lose one of our cleanest generation technologies and one which presently provides about 20 percent of our electricity. Further, growing concerns about global climate change may make it particularly important for us to rely more upon generation technologies which do not emit greenhouse gases. Accordingly, a resource mix that excludes nuclear power is unlikely to be the most economic, reliable, or environmentally benign means of meeting future electricity requirements.

c. In your judgement, can the third world meet its anticipated requirements for electricity without a large expansion of nuclear power?

Answer: The third world can and is expected to meet its anticipated requirements for electricity without a large expansion of nuclear power. Nuclear power currently provides only 1.5 percent of the third world's energy. The Department of Energy's forecasts show that nuclear power's share is expected to increase to only about 2.5 percent by 2010.

Third world utilization of nuclear power is constrained by several factors. One is capital availability. Nuclear power plants are very capital intensive and many third world countries will be unable to raise the necessary capital. A second constraint is the ability of electrical networks in developing countries to absorb a large generating capacity addition. Plants using existing nuclear technology tend to be 1000 MW or larger. Mid-size (600 MW) plants may be commercially available by the mid-1990's. However, even these plants may be too large for a developing country to absorb on its grid. Another constraint is the lack of technical expertise to construct or operate such facilities. In addition, nuclear proliferation concerns may inhibit the use of this technology in developing countries.

As a result, third world countries are not expected to be significant growth markets for nuclear power.

QUESTIONS FROM CHAIRMAN JOHNSTON

The Process Laid Out In Title XII

Questions 1: In your testimony, you identify three main problems with the provisions of title XII -- that DOE is already doing most of the things envisioned under section 12005; that it is too early to expect a utility to order a nuclear plant, even with the benefits of section 12005; and that direct federal government participation in a demonstration project would be inappropriate.

This is a fairly strong rejection of title XII.

Do you really believe that DOE can do everything necessary to revive the nuclear option without any endorsement or encouragement by Congress?

Answer: No, we believe that congressional endorsement of the nuclear option is important and that specific action by the Congress in a number of areas is necessary for the revitalization of nuclear power.

The National Energy Strategy (NES) addresses four prerequisites to future nuclear powerplant orders. They include maintaining exacting safety and design standards, reducing economic risks, reducing regulatory risks, and establishing an effective high-level nuclear waste management program. As you are aware, the Administration has submitted legislation to implement its NES. Two aspects of our legislation are vitally important to the future of nuclear power and require congressional action at the earliest possible time; namely, reform of the nuclear licensing and regulatory process and measures needed to site and license a permanent waste repository and monitored retrievable storage facility. We believe that the Department's reactor programs to develop, standardize, and certify, under 10 CFR Part 52, advanced nuclear powerplants will satisfy the first two prerequisites addressing safety and economic risks.

If all four of these prerequisites are met, the utility industry has indicated that they would once again consider nuclear power to meet new electrical demands. Senior management of nuclear utilities have indicated, in the nuclear industry's Strategic Plan For Building New Nuclear Powerplants, that a demonstration project is not a prerequisite to the next nuclear plant order.

QUESTIONS FROM CHAIRMAN JOHNSTON

NRC Design Certification

Question 2 (a): There is currently some disagreement on what constitutes a standardized design for purposes of receiving a design certification from the Nuclear Regulatory Commission. The disagreement, as I understand it, rests with how much detail would be required for a so-called standardized design to be approved.

On December 27, 1990, Admiral Watkins wrote to NRC Chairman Carr expressing his concern that the NRC may have been planning to require reactor vendors to submit too much design detail, thereby substantially delaying the date by which the NRC could certify a reactor design. On February 15, 1991, the NRC announced its policy on the level of design detail.

Does the NRC's February 15 policy adequately address the Secretary's concerns?

Answer: We are satisfied with the resolution presented in the Nuclear Regulatory Commission (NRC) policy statement. In their statement, the Commission defined the level of detail required for design certification as that necessary to make final safety determinations, with reasonable assurance. This is consistent with the views expressed in Admiral Watkins' correspondence to Chairman Carr. We are closely monitoring implementation of the policy by the NRC staff. We are planning to work with NRC and OMB to establish schedules for the design certification process in accordance with this regulation.

QUESTIONS FROM CHAIRMAN JOHNSTON

NRC Design Certification

Question 2 (b): Based upon what we know now about NRC's policy and process for approval of certified designs, how soon can we expect the NRC to certify each of the advanced reactor designs now being developed?

Answer: In the February 15 communication, the Commission required the staff to provide them, by June 1, with schedules for the design certification reviews. The applicants, the Nuclear Management and Resources Council, and the NRC staff are currently working together to establish mutually agreeable schedules by that date. The objective established by the National Energy Strategy (NES) is to have all four designs certified by 1995. DOE will be participating in interagency reviews of the schedules with NRC and OMB as they are developed and will maintain the position that the objective of the NES should be met.

QUESTIONS FROM CHAIRMAN JOHNSTON

Emergency Planning

Question 3: Resolution of emergency planning issues early enough in the licensing process is a desirable goal for both those looking to license a plant and those who are charged with protection of the public health and safety.

a. Does the Administration's National Energy Strategy bill go further than the NRC rule with respect to emergency planning?

b. Does your legislation envision congressional action on emergency planning issues?

c. What makes you think that Congress is any more likely to legislate away emergency planning issues now than it was when the fate of both Shoreham and Seabrook was hanging in the balance?

Answer: Yes, the Administration's National Energy Strategy (NES) bill does go further than the Nuclear Regulatory Commission (NRC) rule with respect to emergency planning. Our bill requires resolution of emergency planning issues prior to issuance of combined licenses and requires that the combined license shall identify the inspections, tests, exercises, and analyses required for the emergency plan and the acceptance criteria for their satisfactory completion. Further, our bill provides that offsite emergency planning questions arising after a combined license is issued, including those of a decision by a State or locality not to participate in a previously approved State, local, or utility plan, be addressed only in a proceeding to modify or suspend operation under the combined license. Clearly our bill does envision congressional action on these emergency planning issues.

Regarding your third question, we are requesting that Congress take action on offsite emergency planning provisions now because resolution is important to the future use of nuclear power and we believe that the Administration bill incorporates a fair approach which addresses both the needs of prospective plant owners and the public.

QUESTIONS FROM CHAIRMAN JOHNSTON

HTGR Technology

Question 4: Mr. Young, at the hearing, you and I had a discussion about the timing of a demonstration of HTGR technology and, specifically, your concern that a demonstration as envisioned under S.341 would be premature. I am still not sure that I understand your statements, and I hope that you will elaborate.

Specifically, you expressed your hope that if the HTGR technology was used for the new production reactor, then the reactor could also be used as the demonstration necessary to obtain design certification from NRC for the HTGR.

I understand your concern that a utility would not be willing to order an HTGR until the design had been certified by NRC. But I am asking you a different question. I am asking you if the technology is sufficiently developed to build a reactor, and my assumption is that it must be, or else we would not be considering it for a new production reactor. Certainly, we would not be selecting a technology for a new production reactor that is just experimental.

So, assuming that the technology is sufficiently developed to build a reactor, why couldn't you build a HTGR demonstration project, under the provisions of S.341, prior to certification? In fact, why wouldn't it be perfectly appropriate and advantageous to do so? Why wouldn't this, in fact, be the best way to push the technology along and ensure that the design would make it available when a utility was interested in ordering a new plant?

Further, it seems to me that there wouldn't be any need for a demonstration of technology at a later date, after the HTGR design had been certified. At that point, it would be more appropriate for the private sector and the market place to take over. At least that is what everyone is telling me about the need for any demonstration of LWR technology. Therefore it seems to me that instead of an HTGR demonstration being premature, it would actually be quite timely now.

Please elaborate on your comments made at the hearing.

Answer 4 (continued): I would agree with you that there would not be any need for a demonstration of technology at a later date, after the HTGR design had been certified by the NRC. I never intended to suggest such a sequence. The DOE HTGR development program is based on demonstration before certification.

I do not agree with your statement that the HTGR technology is sufficiently developed for a commercial cost-shared demonstration project to be undertaken at this time. The private sector has recently advised DOE that it is not ready to undertake such a project, after many years of preparation for, and anticipation of, such a cost shared approach. DOE is, therefore, exploring an alternative means of bringing the HTGR technology to commercial status. (Even if a commercial demonstration project were feasible, certification by NRC of a commercial design that could be ordered by the private sector would still come after demonstration project completion.)

The development and construction of a New Production Reactor (NPR)-HTGR for tritium production is a highly attractive potential way to demonstrate HTGR technology for eventual application in a commercial HTGR. The NPR-HTGR is on an expedited schedule and many structures, systems, components,

Answer 4 (continued): and other features will be common to both reactors. Use of the NPR-HTGR for technological demonstration would be a cost effective way to conserve government funds in a time of budget restraints.

Within the constraints of their respective missions, the Office of Nuclear Energy and the Office of New Production Reactors have developed designs and schedules to maximize the project infrastructure, technology development, and plant design commonality. A plan is being developed to derive maximum benefits for safety issue resolution including potential demonstration testing with an NPR-HTGR module. This plan will be coordinated in the Department and with NRC. If this development approach is successful, a commercial HTGR design could be certified by 2006, allowing time after the initial NPR operation for preparation of commercial demonstration features in NPR, operating experience, commercial plant design and Safety Analysis Report completion, and three years for NRC review and certification rulemaking.

If the NPR-HTGR is not selected for tritium production in December 1991, it will be necessary for us to reformulate our approach to HTGR commercialization.

Answer 4 (continued):	I reiterate my point that the HTGR is about ten years behind the ALWR because of the need for an approximately ten-year-long HTGR demonstration project to precede NRC design certification. Such a demonstration project is not required for the ALWR.

COMMITTEE ON ENERGY AND NATURAL RESOURCES

Question 5

Following up on the discussion at the hearing on the possibility of a meltdown of HTGR technology, could you please explain the Department's views on this question?

Also, I have been told that, with the HTGR, there would be a potential for release of radiation in the event that the graphite moderator caught on fire. Could you please elaborate on this risk? What would potentially cause the graphite to catch on fire? Under those circumstances, wouldn't it be appropriate to have a containment structure over the reactor to prevent any release of radiation to the accessible environment?

Answer:

Your concerns about meltdown, graphite fires, and a containment structure have been considered for many years by the gas-cooled reactor community including the Nuclear Regulatory Commission (NRC) and overseas high temperature gas-cooled reactor (HTGR) developers. First, it should be said that meltdown is not an appropriate description for the HTGR concept, as HTGR fuel is fully ceramic and its failure, which is at temperatures in excess of 1600 degrees C is characterized by fission product diffusion through barriers that maintain their geometry. The rearrangement of fissionable material in the core or disruption of the core itself does not occur. Of course, HTGR fuel failure potentials and consequences are major concerns. These are being addressed in the modular high temperature gas reactor (MHTGR) by the passive decay heat removal configuration, use

Answer 5 (continued): of high temperature fuel, and the control of pathways for fission product transport to the environs.

The graphite fire potential was evaluated by the NRC (with assistance from Brookhaven National Laboratory) during the Fort St. Vrain licensing process, following the Chernobyl accident and in the course of its preapplication review for the MHTGR. The NRC states that it believes that air availability pathways, including flow channels in the core, would not support a sustained or damaging graphite fire even if a containment structure was not provided. The NRC states that confirmatory experiments might be desirable but has not yet stated this as a requirement. The Department is renewing interactions with the NRC and the subject of graphite fires will be included in these forthcoming discussions.

QUESTIONS FROM SENATOR WALLOP

ALMR

Question 6(a): Would you agree that the long-term promise of nuclear energy is essentially unlimited through the development of advanced liquid metal reactor technologies?

Answer: It was recognized early in the development of nuclear power that if nuclear fission energy is to make a large contribution to the world's energy supply for the long term, that is, beyond a number of decades, a reactor type is needed which can utilize essentially all the fissionable material available in nature from uranium ore, as opposed to the current light water, heavy water, and graphite moderated reactor systems which utilize only about one percent of the energy available in uranium. The advanced nuclear reactor development work carried out worldwide over the past several decades suggest that the liquid metal (sodium) cooled reactor could be suitable for this purpose, and that once deployed, it could supply much of the world's energy needs for centuries.

QUESTIONS FROM SENATOR WALLOP

DOE Program

Question 6(b):	In your judgment should DOE's program be more aggressive in this regard?
Answer:	Within the available budgets, the DOE program is well focused on the highest priority needs for the development of advanced liquid metal reactor technologies.

QUESTIONS FROM SENATOR WALLOP

Nuclear Power Plant Construction Schedules

Question 7: Institution problems are often cited as the reason why we cannot build nuclear power plants in the United States. Japan and France are often used as examples of it taking only four to six years to build a nuclear power plant and put it into operation.

a. Why is this the case in Japan and France? If I am correct, these countries rely on a licensing system similar to that in the United States. Would you comment?

b. Are standardized designs critical to expediting this process?

Answer: There are some significant practical differences in the way the licensing system is implemented in Japan and France. In both countries, there is closer cooperation between the utilities, vendors, and the licensing agencies. Their relationships are less adversarial, and safety issues are resolved earlier. Hearings and legal tactics have not been used to extensively delay or prevent operation of safe plants.

Standardized designs are also important in achieving these construction times. Standardization will eliminate design changes during construction and will enable standardized construction techniques to be implemented.

QUESTIONS FROM SENATOR WALLOP

Nuclear Power Option

Question 8(a): Public confidence in the nuclear power option is essential if it is to play a role in our nation's energy future. Passive safety features are critical to the public's acceptance of nuclear power. Would you agree?

Answer: We certainly agree that the safety of reactors is a critical factor with respect to the public's acceptance of nuclear power. This safety can and must be achieved for any reactor type through a host of measures including its design, operation, and maintenance. The use of passive safety features, such as natural circulation cooling or emergency cooling through gravity, is one path to reducing the probability and/or the consequences of accidents.

In addition, this simplified approach to safety may ease explanations to the public on how the safety regulations are being satisfied. To say, however, that passive features are critical to the public's acceptance of nuclear power, I believe goes too far. Public surveys have shown that a majority of the public would not believe it impossible for a serious accident to occur in a passively safe nuclear plant. Further, while those in industry and government familiar with nuclear technology consider the use of passive design features to be positive, such is not necessarily the case with the public. In fact, a survey has shown adverse public reaction to use of the term "passive" as a design feature, because it conveys negative connotations of inaction to assure safety. The public does believe, however, that future advanced plants will be improved over earlier plants in a number of respects, including safety.

In our view, what is critical is that the industry and regulators continue to maintain a high degree of safety and reliability in the operation of current plants, and that all reasonable steps be taken to provide assurance to the public that adequate safety measures, by several diverse paths, are being taken in the design and operation of any new plants.

QUESTIONS FROM SENATOR WALLOP

Safety

Question 8(b): In your judgment, do liquid metal reactors and high-temperature gas-cooled reactors have advantages with regard to passive safety features?

Answer: These modular advanced reactors, are designed to take full advantage of natural physical laws, thus enhancing their passive safety. The advanced liquid metal reactor and the high temperature gas-cooled reactor are capable of reactor shutdown under adverse conditions without the need for further operator action and decay heat removal.

QUESTIONS FROM SENATOR WALLOP

Nuclear Power Future

Question 8(c): If we are concerned for the future of nuclear power, would you agree that there is a need for a more active Federal support for these technologies in addition to "advanced" light water reactors?

Answer: The Department's Nuclear Energy Strategy is based on an integrated vision of the role nuclear energy can play in the Nation's energy future. In the near-term, between now and 2000, our efforts are focused on new nuclear plant orders based on advanced light water reactor technology as the vehicle for a revitalized nuclear option. Sometime after 2010, advanced nuclear systems that show promise of improvements in safety and waste management potential could be available. Advanced liquid metal reactors (ALMR) and modular high temperature gas reactors (MHTGR) could be available for commercial deployment following successful completion of research, development, and demonstration and design certification by the Nuclear Regulatory Commission.

The budget request for advanced reactor R&D is consistent with the scope and pace of development required for ALMR and MHTGR technologies.

QUESTIONS FROM SENATOR WALLOP

Nuclear Power Industry

Question 9: Would you agree that the future of the nuclear power industry rests in the development of advanced nuclear reactor designs and streamlining the regulatory structure to bring on line new, safer generations of nuclear reactor technologies.

Answer: As outlined in the Administration's National Energy Strategy, we believe that there are four major prerequisites to an expanded role for nuclear power in the United States. Two of these prerequisites address the issues which you raise; namely, maintaining exacting safety and design standards and reducing regulatory risk. The Department of Energy's Advanced Light Water Reactor Program addresses the first of these and will result in an acceleration of the introduction of standardized advanced light water nuclear powerplant designs. This will require not only development, but also the certification of these standardized designs by the Nuclear Regulatory Commission and the performance of the necessary additional detailed engineering work to ensure a high level of commercial standardization in these plant designs. We do not believe that the development of a completely new reactor concept is necessary for the resumption of nuclear orders, but that we should build upon and improve the design based upon the large, world-wide light water reactor technology base. The advanced light water reactor designs that we are supporting will be even safer than the designs of today's plants, which already have an unparalleled safety record through more than 30 years and 1400 reactor years of operation. With respect to the second prerequisite, the Administration has submitted proposed nuclear licensing and regulatory reform legislation.

QUESTION FROM SENATOR WALLOP

Nuclear Advanced Reactor and Licensing Provisions Of S. 341

Question 10: One of the Administration's stated goals in reforming the licensing process is to remove regulatory obstacles to the construction and operation of nuclear plants. Portions of the Administration's proposal are currently addressed in the Nuclear Regulatory Commission's procedures.

a. In your view, how does the Administration's proposal differ from the Commission's existing regulations?

b. Which of the Administration's reform elements could not be accomplished by the NRC under existing statutory authority?

c. Which of the areas covered in the Administration's proposal is, in your opinion, the most crucial to license reform?

Answer: The Administration bill builds upon the Commission's existing regulations by: requiring that the combined license identify the inspections, tests, exercises, and analyses required for the emergency plan and their acceptance criteria, and requiring resolution of emergency planning issues which arise after combined license issuance to be resolved only in a proceeding to modify or suspend operation; establishing an informal post-construction hearing process on issues of nonconformance with the acceptance criteria of a combined license; setting a target duration of a hearing; preventing delay of operation during a hearing unless required for adequate protection of public health and safety; and eliminating delay of operations resulting from combined license amendments if no significant hazards are involved.

There are varying legal opinions as to what extent new legislation would be needed to accomplish the Administration's reforms. All of the areas covered in the Administration's bill are crucial to licensing reform.

QUESTION FROM SENATOR WALLOP

Licensing Reform

Question 11: Opponents of efforts to streamline the licensing scheme by limiting the circumstances that would require a post-construction hearing claim that this limitation would reduce public participation in the process. The provision in S. 341 would retain full public participation on significant safety issues but would consider those issues and provide for their resolution in the combined license proceeding prior to construction. Could you please describe how the Administration's proposal differs from S. 341 in this regard.

Answer: Similar to S. 341, the licensing process in the Administration's bill includes more opportunities for the general public to get their voices heard in a meaningful way--right up front when it is most useful. There is a full public hearing on the suitability of the plant site, a full public hearing on the adequacy of the design to be certified, and a full public hearing prior to the NRC issuing a license to build the plant. After these hearings, the design will be frozen, essentially preventing the builders from making any changes to the design that the public agreed upon.

Both S. 341 and the Administration's bill provide the public with an opportunity to address concerns about whether the construction faithfully conformed with the license at the end of plant construction. However, the Administration's process differs by providing the opportunity for an informal hearing on conformance of the constructed plant with the combined license. Informal hearings are more accessible to, and serve the public interest better, by allowing more efficient application of the Nuclear Regulatory Commission (NRC) technical expertise in resolving the issues raised. The informal hearing procedures would be similar to those used by the Environmental Protection Agency in the administration of the Resource Conservation and Recovery Act and by the NRC in certain proceedings.

In addition to the public input opportunities in the legislation, the public would have the opportunity to request the NRC to revoke, modify, or suspend a plant's license at any time. This opportunity exists under current NRC regulations and is not affected by either S. 341 or the Administration's bill.

GE Nuclear Energy

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March 25, 1991

Honorable J. Bennett Johnston
Chairman, Committee on
Energy and Natural Resources
United States Senate
Washington, DC 20510-6150

Dear Senator Johnston:

In reply to your letter of March 8, 1991 containing questions from Senator Wallop and yourself, I am enclosing my response.

It was a pleasure for me to be able to testify on March 5, 1991 before your Committee on Titles XII and XIII of S.341, the National Energy Security Act of 1991. As I stated in my testimony, I believe that the licensing provisions of Titles XII and XIII are vitally important to the nuclear option in that they clarify Congressional intent and will remove grounds for extended litigation. Let me once more note that the key problems inhibiting the increased use of nuclear power in this country are institutional and not technical. Your proposed legislation addresses the key issues and we support its enactment. Some of the testimony that I and others gave on March 5th were comments aimed at further enhancing this legislation and I have asked my organization to work with your Committee staff so that we can further address the issues and clarify the actions necessary to overcome them.

The Advanced Light Water Reactor (ALWR), with its well established 30-year development, industrial infrastructure, and experience base, is clearly the technology for the near term. This position is reflected by U.S. industry in NPOC's "Strategic Plan for Building New Nuclear Energy Plants," and by DOE in their Light Water Reactor programs. The need for near-term Federal Government support in an "Institutional" Demonstration of an ALWR, as proposed in section 12005 of Title XII of your Bill, is required to demonstrate the workability of the institutional processes and thus to assure that the private sector risk is manageable.

The longer term advanced reactor technologies, such as liquid metal and high temperature gas, lack the extensive 30-year experience base of operating plants, and thus will need a "technical" demonstration to achieve NRC certification and commercialization. Section 12006 of Title XII focuses on this "technical" demonstration. We understand from discussions with your staff that Section 12007 of Title XII provides the appropriations to carry out Section 12006, which we believe will represent a value to the energy security of the U.S. in the next century.

Let me close by thanking you for your continued interest in a viable nuclear option. We look forward to working with you and your staff to ensure its availability for the future energy needs of the U.S.

Very truly yours,

Bertram Wolfe

Bertram Wolfe

Questions
Senator Malcolm Wallop (R-WY)
Nuclear Provisions of S. 341, the Energy Security Act of 1991
March 5, 1991

QUESTIONS FOR ALL WITNESSES

1. The Department of Energy estimates that a combination of increases in demand and retirement of existing electric generation capacity will require an additional 200,000 megawatts of capacity by the year 2010.

Question: a. Would you agree that until recently there has been considerable excess electrical capacity in this country but that this era is coming to an end?

Answer: Yes, as I stated in detail in my testimony, over the last thirty years the nuclear industry has gone through many highs and lows dependent mostly upon the then-current need for additional capacity . Currently, it is projected that there will be a demand for additional generating capacity if we are to maintain our economic prosperity on its present course. Increased efficiency, conservation, and the use of renewable energy resources such as solar and wind power will all help satisfy the need for new electricity supplies, but will fall far short of meeting the demand if the estimate, namely 150-250 gigawatts of electricity in the next twenty years, is born out.

Question: b. Faced with today's environmental laws such as the Clean Air Act, in your judgement, can this requirement for new generation capacity be satisfied without a greater role for nuclear power than is possible under present circumstances?

Answer: As I stated in my testimony, the two major supply alternatives for base load capacity now available are coal and nuclear energy. With the newly legislated constraints placed on burning fossil fuels in the Clean Air Act as well as possibly new restrictions growing out of the concern about the greenhouse effect, we may find ourselves in a situation where nuclear energy is the only practical means to satisfy expanded electrical use.

Question: c. In your judgement, can the third world meet its anticipated requirements for electricity without a large expansion of nuclear power?

Answer: No, I do not believe so. On a global basis the increasing energy and in particular electrical needs of the developing nations, will likely make increased reliance on nuclear power ever more important. If the estimates of thousands of gigawatts of new Third World capacity are born out, there does not appear to be a practical means to meet the requirements without nuclear power. In addition to the papers cited in my testimony, another recent paper by D. M. Donaldson and G.E. Betteridge entitled "Potential Impact of the Greenhouse Effect on Electricity Supply" supports that conclusion. Reprints of the paper are available from the U.S. Council for Energy Awareness in Washington, DC.

Question: 2. a. Would you agree that the long-term promise of nuclear energy is essentially unlimited through development of advanced liquid metal reactor technologies?

Answer: Yes. However, as I indicated in my testimony, the advanced light water reactor (ALWR) is clearly the technology to be used in the next few decades. It has received extensive development, has a well established 30-year industrial infrastructure and experience base, and is already developing new designs based on this experience. The revival of nuclear energy in the U.S. and its widespread use throughout the world raises the issue of the long-term future of nuclear energy. The light water reactors (and other thermal reactor systems) rely on the economic availability of uranium. Although there appears to be sufficient economic uranium to supply ALWRs for some decades, the long-term promise of nuclear energy is an essentially unlimited energy supply through the Advanced Liquid Metal Reactor (ALMR). The ALMR is unique in that it can be made to manufacture (or breed) substantially more fissile material than it consumes. The utilization of this capability of modern ALMRs to breed will be essential sometime in the next century, as the growth in nuclear energy generation using advanced light water reactors, or other non-breeding reactors, consumes the currently abundant uranium supply.

Question: b. In your judgment should DOE's program be more aggressive in this regard?

Answer: Yes. The current ALMR program plan, developed by DOE, the industrial team and the National Labs, is based on a realistic success oriented schedule of focused design and technology development, inclusive of a full scale prototype of the nuclear portion of the plant to support NRC certification of the design about the year 2005. The program, however, continues to face funding shortfalls which either delay its progress or raise the technical risk of first time success.

Congressional support is needed to maintain the viability and momentum of this promising program through consistent funding support to the industrial team's design development with similar support to the required technology development at the National Laboratories. The DOE Fiscal Year 1992 budget as submitted is inadequate to maintain the program's momentum. The industrial design team has reprogrammed the completion of the ALMR's advance conceptual design (Phase 1) to the end of September 1992 (a 1 year delay), based on $14.0 million funding for FY92. This revised plan supports DOE's projection of completing the preliminary design (Phase 2) by FY95, and leads into the longer range prototype program for licensing certification through a government/private sector partnership shortly after the turn of the century (2005). National Laboratory funding for FY92 is also needed at levels no less than current year (FY91) amounts if we are to maintain focused technology support and complete the low risk, success-oriented ALMR program underway.

3. Institution problems are often cited as the reason why we cannot build nuclear power plants in the United States. Japan and France are often used as examples of taking only four to six years to build a nuclear power plant and put it into operation.

Question: a. Why is this the case in Japan and France? If I am correct these countries rely on a licensing system similar to that in the United States. Would you comment?

Answer: During the 1973 Arab Oil Boycott, France and Japan were affected differently than the U.S., which has very large indigenous coal supplies. France has few indigenous fuel resources and had an electric supply system almost completely dependent upon imported oil. A national decision was made to become less dependent on oil and to massively expand the use of nuclear energy. Nuclear power now provides some 80% of France's total electric generation. In Japan, also with few indigenous energy supplies and also heavily dependent on imported oil, the boycott led to a diversification of energy sources in which nuclear energy now supplies 30% of electrical needs. With a projection of 30 large new nuclear plants in the next two decades, nuclear's share will rise to 40%.

These two nations having few other options established, through their legislative bodies, expansion of nuclear power as a vital national interest and policy. Legislation and institutions were put in place which would enable expedited development in an economic, safe and environmentally sound manner. These countries, in fact, adopted and continue to build light water reactor plants based on technologies licensed from United States companies. The light water reactor technology, which some allege is flawed and should not be utilized for new plants in the U.S., is continuing to be applied very successfully in numerous other countries.

A stark difference between the implementation in this country and others, particularly Japan, is the degree of national consensus surrounding the nuclear programs. Leaders of the national government as well as those from the broad industrial community have steadfastly supported nuclear power as necessary for the general well-being and prosperity of the nation. As noted in my testimony, there was no need in our country for additional power plants so no broad consensus was possible. Difficult choices did not have to be made. Additionally, unlike the others, we are a very litigious society. These two factors resulted in small groups of activists being able to utilize our legal system to prevent or delay (making costs soar) the construction or operation of nuclear power plants.

If nuclear energy is to help the country meet its future energy needs in an environmentally sound manner thereby maintaining our economic strength and standard of living, national leaders must forge a consensus that expanded use of nuclear power is needed. Legislation and institutional reform must be implemented so that prudent investors can once again build nuclear power plants in a stable regulatory and legal environment.

Question: b. Are standardized designs critical to expediting this process?

Answer: Yes, the licensing process is, even in the best of circumstances, necessarily time and resource intensive. The regulatory infrastructure and the nuclear industry cannot support dozens of parallel reviews of different plant designs. The only practical way to achieve a reasonably timely, efficient and certain outcome is by licensing a few standardized plants which can then be built repetitively without further regulatory review of the design. This standardization approach is similar to that taken in France and Japan. For example, Japan, which has multiple utilities and competitive vendors such as the U.S., has standardized on two basic types of light water reactors, the boiling water reactor (BWR) and the pressurized water reactor (PWR). Within each type there has been a series of specific standardization programs, each of which resulted in the construction of up to 10 power plants. The results of the third BWR standardization program, GE's ABWR, is about to begin construction. The licensing documentation and requirements for plants within each standardized series are essentially identical.

When such a process is realized in this country, most resources can be applied to reviewing the construction process via the inspections, tests, analyses and acceptance criteria (ITAACs). This will enable timely construction progress as experienced in other countries.

The nuclear industry as a whole is committed to extensive standardization. Recently, the Nuclear Power Oversight Committee (NPOC), a committee of senior utility and industry executives charged with establishing policy for the nuclear industry in this country, issued a statement outlining the industry's "life-cycle commitment to the uniformity in the design, construction and operation of a family of nuclear power plants"

4. Public confidence in the nuclear power option is essential if it is to play a role in our nation's energy future.

Question: a. Passive safety features are critical to the public's acceptance of nuclear power. Would you agree?

Answer: No, the results of recent public opinion surveys would not lead one to that conclusion. The public responded most favorably to "improved" nuclear power plant rather than "passive", "inherently-safe", etc. I believe the new light water plants now undergoing NRC review for certification will be acceptable to the public, especially after comparing the pro's and con's of alternate sources. These new light water plants have been greatly simplified, employ a combination of active and passive features and represent large improvements relative to current, successfully operating nuclear plants. However, even the so-called "passive" designs depend upon valves, relays, and other electrical or mechanical devices to put the plant into a condition where "passive" systems can take over. Thus, I am concerned that overemphasis on "passive" safety could be interpreted as misleading the public and ultimately cause disillusionment and loss of creditability of the industry.

Question: b. In your judgement, do liquid metal reactors and high-temperature gas cooled reactors have advantages with regard to passive safety features?

Answer: All reactors including advanced reactors have imaginative events of extremely low probabilities which can cause a severe accident. However, all current and planned designs meet, or will meet, the requirements and guidelines set forth by the NRC. These designs compare favorably to alternate (non-nuclear) electricity sources in terms of public protection from adverse effects. When comparing the safety performance of different reactor designs, a more valid comparison is the potential amount of radiation release under the low probability (beyond design basis) events even though the mechanisms for potential release are different. This consideration of imaginatively very low probability sequences which have the potential for a large radioactive release has to be dealt with by the specific characteristics of the coolant and the design response to potential events. Exclusive use of passive systems is not always the best (or only) approach to achieve a desired balance of prevention and mitigation. In most cases, an appropriate combination of prevention (that is low probability of an event achieved through active and/or passive systems) and mitigation (that is containment of a potential release in the event a low probability severe accident occurs) is used to reach acceptable safety performance. For example, while most discussions of passive approaches focus on prevention, an important mitigation approach utilizing a passive system is the containment structure included in current operating plants as well as in advanced ALWR designs, such as ABWR and SBWR, and the ALMR. In these designs, the containment structure mitigates a low probability core disruption event through containment and control of the potential release which might jeopardize public health and safety. The addition of containment in the design of the commercial MHTGR is still an open issue although the NPR (defense) version of the HTGR includes a containment structure. Thus in spite of extremely low probabilities of a core disruption event, inclusion of a containment for the commercial MHTGR would improve its mitigation capability by passive means although it may complicate or make infeasible other passive safety elements and adversely effect non-safety aspects of the plant, such as its economics.

Question: c. If we are concerned for the future of nuclear power, would you agree that there is a need for a more active Federal support for these technologies in addition to "advanced" light water reactors?

Answer: Yes. The DOE advanced light water reactor budget for fiscal year 92 is consistent with the ABWR and SBWR program plans for successful NRC certification in 1992 and 1995 respectively, and we urge your continued support. However, the revival of nuclear energy in the U.S. and its widespread use throughout the world raises the issue of the long-term future of nuclear energy. The advanced light water reactors (and other thermal reactor systems such as the MHTGR) rely on the economic availability of uranium. Although there appears to be sufficient uranium to supply these reactors for some time, the long-term promise of nuclear energy is an essentially unlimited energy supply through the Advanced Liquid Metal Reactor (ALMR). Since we have learned that it takes several decades to develop, test, correct and improve new reactor concepts, our national energy policy and supporting development programs should include timely and consistent ALMR development and demonstration.

As stated in response to question 2.b the current ALMR program plan is realistic and consistent with a low risk development and demonstration. We agree that active and consistent Federal support, from Congress and DOE, is needed to assure its development, prototype demonstration, NRC certification and readiness for commercial deployment prior to its need in the market place.

5. Would you agree that the future of the nuclear power industry rests in the development of advanced reactor designs and streamlining the regulatory structure to bring on line new, safer generations of nuclear reactor technologies.

Answer: Yes, both of these items are necessary to the reemergence of nuclear power in the United States, however, they are not sufficient.

With respect to the development of advanced reactor designs, as I mentioned in my testimony, I am pleased to report that from a technological standpoint the U.S. nuclear industry will be ready. Because of development work here and abroad and new programs in this country, I believe we will be able to bring much improved technology in advanced nuclear plants to the nation and the world.

As I also indicated in my testimony, the key problems inhibiting the increased use of nuclear power in this country are institutional, not technical. At the forefront of these institutional impediments is our licensing system. Fortunately, there are some initiatives aimed at correcting our nuclear licensing situation. The joint DOE/EPRI/industry program to pre-license standardized plant designs underway with the NRC is very helpful. Additionally, I believe that the licensing provisions of title XII and title XIII are vitally important in that they clarify Congressional intent and will remove grounds for extended litigation.

In addition to these two critical items, there are a number of other items which must also be addressed. They include resolution of issues related to radioactive waste management, state economic regulation, plant ownership and financing, and public acceptance.

NEED FOR TECHNOLOGY DEMONSTRATION

1. In your statement, you spoke mostly about the need for institutional improvements -- such as licensing -- concluding that the development of technology is sufficient, on course to ensure that designs will be developed and proven when needed. What I hear you saying is that there is no role for a demonstration project at this time.

Questions:
a. Is that your view?
b. Is that because the technology is not ready to demonstrate, or because you just don't believe a demonstration would be helpful?

Answer: My intention was to state that there are two types of demonstration needed depending upon the state of development of the technology.

The first type of demonstration addresses the problem facing us in this country of our 18-year history of delays, escalating requirements and costs, and abandonments during the construction phase of a nuclear project. Whereas abroad nuclear projects are built on firm schedules with firm prices, no sane nuclear plant manufacturer or constructor would today make such an offer in the U.S., and with the past experience no utility is ready to undertake the risk. Thus, we need a means to demonstrate that with the new standardization licensing procedure, plants in the U.S. can be built efficiently in the four to six-year time frame that is achieved abroad. Your title XII addresses this problem and, in particular, provides for Government "insurance" if new regulatory requirements are imposed after the issuance of a license.

We believe this type of demonstration, which I'll call an "institutional demonstration", is covered under title XII in Section 12005. That section identifies a process which will provide government assurance to investors that the project will be protected from new requirements imposed by the Commission after issuance of a license. We believe this Section should be applied to near term application of light water reactor technologies and furthermore the protection provided should be expanded to address other risks associated with construction of the initial units. The investors will accept the internal risks associated with the project cost and schedule, but certain external risks which have crippled nuclear projects in the past cannot be reasonably assumed.

Prior to the commencement of construction, future nuclear power projects must, in addition to NRC licensing, have agreement with state and local authorities in numerous areas. Section 12005 should be expanded to protect investors from changes in the requirements in such areas after commencement of construction.
The cost to the government of this approach would be zero if all prior agreements were honored in a timely manner. However, utilization of the protection provided by this Section should not require that the government share in the revenues from operation of the facility since this would effectively dilute the equity of the investors through no fault of their own. Under the current provisions, the investor would ultimately be assuming the risk of new requirements which defeats the purpose of the Section.

The second type of demonstration which we believe is provided for in Section 12006 should be a demonstration of technology, not process. This "technology demonstration" should be utilized to develop and demonstrate longer term options such as the ALMR and MHTGR. Those technologies are discussed below.

Finally, Section 12003(a) proposes certain nuclear plant features which being subject to interpretation could inhibit support for promising systems and, therefore, should be utilized in a non-exclusionary way. For example, all of the advanced light water reactors depend upon valves, relays, and other electrical or mechanical devices to put the plant into a condition where "passive" systems take over. Ambiguities of interpretation could be overly restrictive. Thus, I suggest you make clear that the prime requirements for support, consistent with the recently issued NPOC strategy plan, are safety, cost effectiveness, and standardization.

Question: c. At what point would the technology be ready to demonstrate?

Answer: GE's ABWR, which will start construction in Japan this year, is leading the way toward NRC certification of advanced standardized designs and is in fact ready now for an "institutional demonstration" in this country. ABB-CE's System 80+ design is following the ABWR towards certification and should be ready a couple of years later. We expect GE's SBWR, as well as W AP-600, to be ready for a demonstration in 1995 following NRC approval. The ALMR and MHTGR will need a "technology demonstration" currently planned through their prototype test program but may not need an "institutional demonstration" if the ALWR programs are successful.

Question: d. How many years are we away from commercialization of the more advanced technologies, such as the high temperature gas-cooled reactor or the liquid metal reactor?

Answer: As stated above, a technical prototype demonstration of the ALMR and MHTGR will be needed to supplement R&D programs and design analysis to achieve NRC certification. The current ALMR program plan has integrated the R&D at various national laboratories with the design and licensing activities of the industrial team to target establishment of commercial feasibility by 1995. Based on successful program results similar to those achieved to date, we would expect to proceed with a government - private sector partnership to finalize the design, and construct and test a full scale prototype unit by 2003. This would lead to NRC certification (after rulemaking proceedings) and readiness for commercialization by 2005. I'm not familiar with the detailed MHTGR schedule; however, I believe the MHTGR will have similar requirements and thus could also be ready for commercialization, following a prototype demonstration, after the turn of the century.

ADVANTAGES/DISADVANTAGES OF LIQUID METAL TECHNOLOGY

2. Obviously, there may be certain advantages to development of a commercial liquid metal reactor, such as its capability to breed and the potential for minimization of waste.

Question: a. Do you believe that concerns about fuel reprocessing and nuclear weapons proliferation would discourage the development or commercialization of LMRs?

Answer: No, I don't think so. The DOE program for processing of spent fuel is based on establishing the pyroprocessing technology (IFR) being developed at Argonne National Laboratory (ANL). This process has diversion resistance and non-proliferation advantages over previous reprocessing approaches as the fissionable materials are recovered along with other impurities. We believe that a demonstration of this process will show that such improved processing and recycle can be carried out in a manner consistent with U.S. non-proliferation goals.

Question: b. Wouldn't the existence of these public concerns be a good reason for a demonstration of the technology?

Answer: Yes, we agree a demonstration is appropriate. The technology demonstration program already under way at ANL will provide this demonstration and the basis for achieving technical feasibility and public acceptance by 1995. The commercial (and economic) acceptance by utilities will follow as part of the ALMR prototype and commercialization program.

Question: c. How many years away are we from being able to prove the ability to significantly reduce the volumes of nuclear waste by actinide burning?

Answer: The actinide recycle technical feasibility of the ALMR program using the IFR fuel cycle approach will be established by 1995 under current DOE program planning, if adequate Federal resources (funds) are provided. Following the technical feasibility demonstration the actinide recycle potential and its impact on the U.S. High Level Waste solution could be integrated with current planning of the geological repository (which is scheduled for first material receipt in 2010) and the ALMR prototype demonstration (which is scheduled for completion by 2005).

THE PROCESS LAID OUT IN TITLE XII

3. You express a concern in your statement that title XII may be overly restrictive and could replace valuable ongoing R&D programs. The authority in title XII is intended to be in addition to existing authority for R&D programs.

Question: a. Would your concerns about title XII be diminished if it did not reduce the available funds for existing R&D programs?

Answer: Yes. Title XII needs to be clarified to assure support for current DOE advanced reactor programs which are well defined, at various stages of completion and aimed at an early "institutional demonstration" of an advanced light water reactor, such as ABWR. The Federal support should be consistent with these program plans in order to assure timely and effective results. Title XII, Section 12007, as written, does not tie funding into the specific programs and thus could be limiting in achieving targeted results.

Question: b. Would you then support a demonstration such as envisioned in title XII?

Answer: As stated in responses to the questions above on Technology Demonstration, we support an "institutional demonstration" of an ALWR under an expanded Section 12005 whereby the Federal government provides "insurance" if new institutional requirements are imposed after issuance of a license for a standardized design. We additionally support Federal involvement in a "technical demonstration" of an advanced reactor, such as the ALMR and MHTGR, through the government/private sector partnership proposed in the program plan. This appears to be consistent with Section 12006 of title XII.

Question: c. Do you share Mr. Young's concern that title XII might actually harm the Department's current efforts to develop advanced reactors?

Answer: I am not sure what Mr. Young's concerns are. My response to Question a. above covers my concerns with title XII. In general, title XII should provide the flexibility to enhance current DOE programs, not limit, constrain or rearrange them. For example, ALWR first of a kind engineering support to be effective should follow NRC issuing a Final Design Approval (FDA) and perhaps work in parallel with the rulemaking procedures leading to certification of the design. This kind of support is not now covered in title XII and might, therefore, actually harm DOE program plans. This may be part of Mr. Young's concerns.

4. You say that you don't believe an advanced light water reactor -- the mid-sized so-called passively safe designs -- would qualify for a demonstration project under section 12006.

Question: a. Why not?

Answer: Advanced light water reactor technology, including that in so-called passively safe designs, is well demonstrated technically or can be most economically tested in non power reactor test facilities. Thus, the federal government's role should be to enable the private sector to implement that technology in the new Advanced Light Water Reactors under Section 12005 protected from the financial risks associated with changes in government policies and requirements.

Question: b. Why wouldn't this be attractive to a utility looking to build a mid-sized advanced light water reactor?

Answer: While I cannot speak for the utilities, I believe that the major risks associated with light water reactor technologies after the designs have been certified and a substantial portion of the First-Of-A-Kind Engineering has been completed will be related to external regulatory changes. Government participation directly in a project is not necessary since implementation of proven technology is more appropriately the role of the private sector.

Additionally, limited government funding would be better applied to enable development of advanced technologies which are promising in the longer term but are unlikely to receive near-term private funding due to the high technology risk early in their development. This support for research and development of advanced technologies has been a role which government has traditionally and successfully performed.

CERTIFICATION OF STANDARD DESIGNS

5. There is currently some disagreement on what constitutes a standardized design for purposes of receiving a design certification from the Nuclear Regulatory Commission. The disagreement, as I understand it, rests with how much design detail, thereby substantially delaying the date by which the NRC could certify a reactor design.

On February 15, 1991, the NRC announced its policy on the level of design detail.

Question: Does the NRC's policy adequately address the concerns of reactor vendors?

Answer: The Commission issued its guidance to the staff in the form of a Staff Requirements Memorandum (SRM) on February 15, 1991 pertaining to level of design detail and related Part 52 implementation issues. As I stated in my letter to Chairman Carr on February 28th, I believe that the Commission has charted a reasonable and balanced course, one that provides a sound basis for proceeding with the ALWR applications under review by the staff.

I went on to state that GE intends to work diligently with the Commission and its staff to complete the final design approval and design certification phases of the ABWR review. This will be a major step in demonstrating that the new regulatory regime which Part 52 articulates can lead to the predictable and stable regulatory process intended.

GE believes that the Commission guidance resolves the major issues leaving the details to be worked out with the staff. Based on our experience to date, these do not appear to be insurmountable.

6. Based upon what we know about NRC's policy and process for approval of certified designs --

Question: a. How soon can we expect the NRC to certify each of the advanced reactor designs now being developed?

Answer: GE is working diligently with the staff to establish realistic schedules for completing the final design approval (FDA) and design certification phases of the ABWR review. As a first step, GE proposed its plans and actions to complete all ABWR submittals this summer clearing the way for issuance of the FDA by the end of 1991. The design certification phase is estimated to be completed within 12 to 15 months of FDA issuance.

ABB-CE's System 80+ will likely be certified about 2 years after the ABWR. Both GE's SBWR and W AP-600 are scheduled for certification in 1995. These schedules depend greatly on the timely and consistent implementation of the abovementioned Commission certification course on the ABWR, which is the first plant being certified.

Question: b. How much will it cost a reactor vendor to develop and obtain NRC certification for a new reactor design?

Answer: The cost of developing and obtaining NRC certification for a new reactor design depends greatly on the status of the technology and the design at the beginning of the program. The typical cost for NRC certification of an advanced light water (ALWR) design, starting from a conceptual design, is $200 million. These designs, as I noted earlier, are based on thirty years of technology development and operating experience. For designs such as the ALMR and MHTGR, for which the technology and operating base is less developed and therefore require prototype demonstrations, the cost of the total program will exceed $ 1 billion.

GE's ABWR Design Certification Program is budgeted at only $25.8 million. This amount is cost shared between GE and DOE. This limited budget was possible because the design effort, including required test and development, was performed by GE and our associates in support of the plants we are about to build in Japan. Only the U.S. licensing effort had to be supported. I believe a similar situation exists for the ABB-CE System 80+ design.

Only the conceptual design of GE's SBWR had been completed prior to commencement of the Design Certification Program. The total program cost through certification is budgeted at $140 million. DOE is providing $48.5 million in funding with the remainder provided by the private sector. Additionally, we estimate we have avoided approximately $75 million of development cost by applying much of the advanced technology we developed for ABWR. I understand the W AP-600 has a similar cost profile.

Following certification of the ALWR designs and prior to commencement of construction, another large effort will be required to meet the ALWR utility requirement for design completeness. The nuclear industry as part of its standardization policy has stated that 90% of the detailed design should be completed prior to placement of first concrete at a new plant. In order to complete this design effort, known as First-Of-A-Kind (FOAK) Engineering, we estimate that typically an additional $200 million is required for each design, although this number will also vary based on the pre-program status of the design. Discussions are underway in the industry, including DOE and EPRI, to define programs and funding methods to accomplish this effort.

Question: 7 a. What is the problem at NRC?

Answer: The ABWR technical review got off to a good start and initial progress was excellent. In spite of its good start, however, the ABWR review has recently been affected by process difficulties within the NRC. The first setback came in December 1989 when the Commission reexamined its role in the ALWR programs and provided the NRC staff with a new review procedure to be used on these programs. The new procedure is intended to involve the Commission early in the resolution of ALWR policy issues. Unfortunately, the procedure for early Commission involvement came very late in the ABWR certification effort. The impact of this new procedure was a 10 to 15 month delay.

Most recently the Commission has reexamined the level of design detail required for certification. This issue was addressed early in the licensing review bases discussions in 1986 and 1987 by GE, the staff, the ACRS and the Commission and we believed we had agreement on the detail required. Unfortunately, this level of detail issue reemerged much later at a time when the ABWR SSAR had been virtually completed and the NRC staff technical review was nearing completion. While this issue has again apparently been resolved by the Commission policy discussed above, significant delay was experienced by this uncertainty with respect to process.

The NRC is regulating an industry with very long product cycles compared to other industries. The ABWR was conceived in 1978 and will enter operation in Japan in 1996. The licensing process in the U.S. began in 1986 and we trust will result in NRC certification in 1992. Construction of the initial unit will take an additional six years. Operation is planned for an additional sixty years. During this entire period large investments are being made which critically depend upon the stability, predictability and finality of NRC policies and positions. Conversely, the NRC Commission, as well as other regulatory bodies such as Public Utility Commissions, has a relatively short cycle of change. Each new Commissioner brings his or her own perspective to the position and the institutional memory has tended to be very short. Until a reformed NRC licensing process is codified as proposed, in part, in title XIII and a Congressional mandate for a stable licensing environment is given, I fear the industry will face major, perhaps insurmountable, uncertainties and obstacles to the detriment of the nation.

Question: 7 b. What can Congress do to get the NRC back on schedule?

Answer: The outlook for successful demonstration of the new licensing process is at a critical point. The task at hand is to restore meaningful project schedules and permit expeditious processing and issuance of the final design approval (FDA) followed by design certification through rulemaking for the ABWR. To do so would permit the start of the institutional reactor demonstration project (described above) needed to restore the nuclear option. GE, in a joint program with DOE, remains committed to do its part to successfully demonstrate the workability of the new licensing process. Congress' continued support of funding authorizations is essential.

Congressional oversight is also clearly needed to monitor the process. An active Congressional interest in the causes for institutional delays and in achieving timely remedial action is an important aspect of productive oversight. Constructive interest in NRC Certification delays, such as that expressed in last year's report[1] of the Senate Subcommittee on Energy and Water Development, is very helpful in maintaining a clear, goal-oriented course.

1) Report of the Senate Subcommittee on Energy and Water Development, Committee on Appropriations (S.Rep. No. 101-376, 101st Congress, 2d Sess, July 14, 1990 at 199).

Questions
Senator Malcolm Wallop (R-WY)
Nuclear Advanced Reactor and Licensing
provisions of S.341, the Energy Security Act of 1991
March 5, 1991

QUESTIONS FOR BERTRAM WOLFE

Question: You point out that today's nuclear technology is very different from that of 30 years ago when commercial nuclear plants began operating. Could you please state those advances you feel are most significant in relationship to efficiency, economy and enhanced safety features?

Answer: Over the past thirty years, light water reactor technology has matured and been proven. We have encountered difficulties as we gained experience along the way; however, we have responded positively to the challenges and now have a demonstrated capability to design, build and operate even better plants in a safe, economical, and environmentally sound manner. While other advanced technologies are in development, the advanced light water reactor is ready now for large scale deployment.

In viewing the evolution of GE's boiling water reactor (BWR) over the past three decades three trends become evident which I'll discuss in more detail below. These trends are first, the growth in plant electrical output; second, the simplification of the basic reactor and containment designs; and finally, the increase in safety.

General Electric selected the boiling water reactor (BWR) as the most promising commercial nuclear power concept because of its inherent advantages in control and simplicity, and established an atomic power equipment business in 1955 to offer it commercially.

The beginning of the GE BWR product line was the Vallecitos BWR in 1957, which was located in California. This reactor powered a 5-MWe generator and provided power to the Pacific Gas and Electric Company grid through 1963. A major extrapolation from that first test facility is the Dresden 1 plant, located in Morris, Illinois. Order for the 180 MWe plant was placed in 1955, with commercial power production achieved in August of 1960.

The value of the BWR concept has been proven by the designs GE evolved over the subsequent decades. The Oyster Creek plant, located in Toms River, New Jersey, was the first large direct cycle light water reactor. This plant which entered operation in 1969 had an output well over 500 MWe, truly a commercial size, economical power plant. The BWR continued a disciplined, evolutionary, building-block approach, supported at each step by research and testing towards larger size power plants to take full advantage of the economy of scale. Power plants of 1100-1300 MWe were introduced in the mid-seventies. The ABWR, a 1300 MWe power plant, is the most advanced plant design in that series. In response to the need for a mid-size power plant, GE is also developing the 600 MWe SBWR.

The second trend noted is the evolution of the BWR toward simplification in two major areas - the reactor system and the containment design. This evolution resulted from design enhancements and experience gained from operating reactors, abnormal occurrences and test programs. Both the ABWR and SBWR are the results of this progressive simplification.

The earliest BWR were very similar to pressurized water reactors (PWRs) and had primary and secondary loops. However, the first large BWR, Dresden 1, a dual cycle plant, provided steam flow directly using an elevated steam drum and also via a secondary steam generator to the turbine. The first major simplification came with the introduction of internal steam separators and dryers to replace the external steam drum. This also lead to the elimination of the steam generators and to the first direct cycle BWRs in the late 60s. These designs had five external recirculation loops, which were soon replaced by two loops with the introduction of internal jet pumps. This process of continuing BWR simplification culminated in the next logical step for large plants: total elimination of the external loops and jet pumps and use of internal pumps on the ABWR. For smaller plants, like the SBWR, total elimination of all recirculation pumps was made possible by the use of natural circulation.

The containment design evolution has had a similar extensive history with the design always tending towards simplified construction, enhanced safety, and plant protection. Early BWRs were housed in large volume dry containments of a spherical design similar to many PWRs today. However, the pressure suppression containment was developed and became a standard feature of BWRs, because of its many advantages: high heat capacity; lower design pressure; depressurization capability; fission product scrubbing and retention; and provision of a large source of readily available makeup water.

BWR pressure suppression containment design evolved from the early Mk I design with its characteristic torus/lightbulb arrangement, the Mk II where the larger drywell provided more room for the steam and emergency core cooling systems (ECCS) piping, to the Mk III design with its simple cylindrical shape for ease of construction and horizontal vents for reduced dynamic loads. The containment also evolved from the all-steel, free-standing (in many cases) structures to the reinforced concrete containment design.

The next logical step in the containment evolution was to take the best features of the previous designs and develop an optimized design to meet the performance, construction and cost goals of our ALWRs. The cylindrical shaped reinforced concrete containment was chosen for both the ABWR and SBWR. Many of the standard features of the BWR containments enumerated above are, in fact, being adopted in other advanced passive designs.

The final trend I'll discuss is related to increases in safety. These improvements were driven by technology advances, lessons learned and regulation. The first nuclear reactor at Stag Field at the University of Chicago you'll recall was contained only by a grandstand and the safety control rods depended on an axe. We've understandably come a long way.

The first major decision in safety assurance was to require all commercial nuclear power plants to have containments which could protect the public in case of an accident. Today, it seems clearly evident that such containments are prudent However, others, specifically the Soviets, took a different approach. Their reactor designed without containments and with other flaws, led to disastrous results. While light water reactor technology was in its infancy when the decision for containment was made and many risks we have recognized and dealt with over the years were unimagined, the industry made a conservative and in retrospect a wise decision. This single feature lowered the risk to the public by a significant degree.

Emergency core cooling systems (ECCS) were the next major safety feature conceived. These systems, with their emergency backup diesel sources of AC power, greatly reduced the probability of core damage due to loss of coolant. These systems have been greatly improved over the years, as I will discuss later. The ABWR design incorporates three redundant and independent divisions of ECCS and containment heat removal. The SBWR uses gravity and other natural forces to provide these functions.

The final major advancement which I'll discuss is the improvement in design codes and practices utilized to ensure the containment and other vital structures will withstand seismic events without jeopardizing the power plant or the public. Hundreds of millions of dollars have been spent in characterizing through testing, modeling on high speed computers and incorporating in the design the forces which will act upon the plant during an earthquake.

These three features are fundamental to nuclear safety and in combination reduce the risk to the public by five or six orders of magnitude. However, even with these features, our job was not complete. We have continued in numerous ways to improve safety. I'll mention a few of the more significant improvements, but will not attempt to give a complete accounting. Items such as reduced occupational exposure, hydrogen control, post-accident equipment qualification, electrical separation, fire protection, post accident monitoring, improved operator interface, probabilistic risk assessments and failure modes/effects analysis, and provisions for severe accidents are worthy of note.

The current fleet of operating plants has incorporated these improvements and represent an extremely safe, reliable source of electrical power. Their performance has improved significantly in recent years. However, once again the industry was not content. In establishing the requirements for the advanced light water reactors and in completing their design, significant additional improvements have been made. I have included a table of key performance characteristics which illustrates my point. Many of the characteristics listed for GE Operating BWRs are significant improvements over the record of just a few years ago and represent the results of an on-going effort by the industry to improve the performance of the current operating fleet. We are confident, however, that our advanced BWR plants will greatly exceed even the improved performance levels of the operating plants as the key performance characteristics table shows.

In discussing the improvements I'll focus on safety, an area in which the ABWR and SBWR plants have built upon and improved the fundamental safety features of all boiling water reactors.

With respect to controlling the reactivity or power level of the reactor, these advanced plants incorporate electro-hydraulic fine motion control rod drives, which provide electrical fine rod motion during normal operation and hydraulic pressure for immediate shutdown (scram). The electric motor also gives increased reliability over current hydraulic-only drives for the scram function by providing a diverse back-up electrical motor run-in following scram. Also, the drives do not require a scram discharge volume thus eliminating a potential source of common mode failure. The Standby Liquid Control System is a manually initiated, boron injection system which has a safety related function for backup reactivity control as in previous BWR designs.

The ABWR safety systems design has been significantly improved over past designs and incorporates three redundant and totally independent divisions of ECCS and containment heat removal. The ECCS prevents any core uncovery for all design basis Loss Of Coolant Accidents (LOCA). Each division has its own emergency diesel generator and one high pressure and one low pressure inventory makeup system. Additionally, a non-safety grade combustion turbine-generator is provided as a diverse source of backup AC power.

The SBWR accomplishes the same results (no core uncovery for all design basis events and post-accident containment cooling) as the ABWR, however, we adopted a more passive approach. The SBWR utilizes a Gravity Driven Core Cooling System (GDCS) and a Passive Containment Cooling System (PCCS).

As a result of these improvements there is a substantial increase in safety performance margin in these designs over the already outstanding capability of earlier BWRs. The risk of core damage is calculated to be 10 times less than earlier designs.

Several passive features have been added to both the ABWR and SBWR designs to mitigate the consequences of a severe accident in the extremely unlikely event one should occur. The containment atmosphere is inerted with nitrogen gas to prevent the evolution of hydrogen from causing combustion or detonation and threatening the containment integrity. A system has been included which passively floods the area under the Reactor Pressure Vessel with water to cool the core debris and thus reduce the threat of containment overpressurization. This system is initiated by high temperatures in the area (caused by the debris) which passively open fusible plug valves. Water then flows from the suppression pool by gravity. The suppression pool, as in all BWR pressure suppression containments, serves as a fission product scrubber removing most of the fission products released due to the accident from the steam and entrained gases as they pass through the suppression pool water during the quenching process.

On the ABWR, the containment also has a passive overpressure protection device to prevent containment failure even under extreme conditions where containment cooling is assumed to be unavailable. A rupture disk opens to allow release of the containment pressure and decay heat while most of the radioactive fission products are retained in the suppression pool.

Once again the SBWR accomplishes the same public protection goal in a different manner. Due to the passive nature of the containment cooling system, it is much less likely that the function would be unavailable; therefore, no overpressure protection is provided. However, the potential for installing a vent is still under consideration.

With their safety features, both the ABWR and the SBWR greatly surpass the ALWR goal for protection of the public.

Another major advancement in safety is the Safety System Logic and Control (SSLC) system which integrates the logic for the reactor trip, containment isolation and emergency core cooling functions. The SSLC together with the Essential Multiplexing System, a fiber-optic network, consolidates all the data acquisition and logic processing equipment for the plant protection functions. These systems are microprocessor-based, fault tolerant, and include extensive self-test and self-diagnostic functions. Four essential divisions, totally separated from each other and the non-essential functions, are provided for absolute assurance of function.

Both the ABWR and SBWR designs exceed established safety requirements outlined for advanced reactor designs. They incorporate, in my view, the best approach to plant safety namely an optimal combination of active and passive features which provides the maximum assurance of safety in an economical, environmentally sound power plant.

In summary, over the past thirty years, light water reactor technology has matured and been proven. We have encountered difficulties as we gained experience along the way; however, we have responded positively to the challenges and now have a demonstrated capability to design, build and operate even better plants in a safe, economical, and environmentally sound manner. While other advanced technologies are in development, the advanced light water reactor is ready now for large scale deployment.

Question: You state in your testimony that our licensing system is at the forefront of institutional impediments to increased use of nuclear power. What factor or factors do you believe pose the greatest hindrance to increased nuclear development?

Answer: As I indicated earlier in my responses, the key problems inhibiting the increased use of nuclear power in this country are institutional, not technical. I went on to note that at the forefront of these institutional impediments is our licensing system but that there are some initiatives aimed at correcting the situation. The licensing provisions of title XII and title XIII are vitally important in that they clarify Congressional intent and will remove grounds for extended litigation.

In addition to these items, there are a number of other items which must also be addressed. The most concise statement of all the conditions which must exist if the use of nuclear power is to increase is contained in the NPOC Strategic Plan. Of the fourteen elements, there are a number in the plan, in addition to licensing reform and commercialization issues, which require congressional support to achieve. These include high-level radioactive waste management, adequate fuel supply, enhanced public and political acceptance, clarification of plant ownership & financing, and possibly state regulatory issues. Leaders of the nuclear community look forward to working with the Congress so that solutions to these difficult issues may be found and nuclear energy will make an even greater contribution toward meeting the nation's energy requirements.

BWR Key Performance Characteristics

	GE Operating BWRs	ABWR	SBWR
Net electrical output (MWe)	600-1300	1300	600
Construction schedule (months)	80-140	42[2]	36[2]
Unplanned scrams/year	2	<1	<1
Availability factor (%)	75[1]	86	86
Daily load following range (% of rated power)	50-100	50-100	50-100
Core damage probability (per year)	$10^{-4} - 10^{-5}$	$<10^{-6}$	$<10^{-6}$
Occupational exposure (man-rem/year)	450 av[1]	<100	<100
Solid radwaste (m^3/year)	300 av[1]	<100	<100
Overnight capital cost ($/kWe)[3]	2000-4000	1280	1610
Production cost (¢/kWhr)[3]	1.4 - 5.3[1]	1.6	2.0

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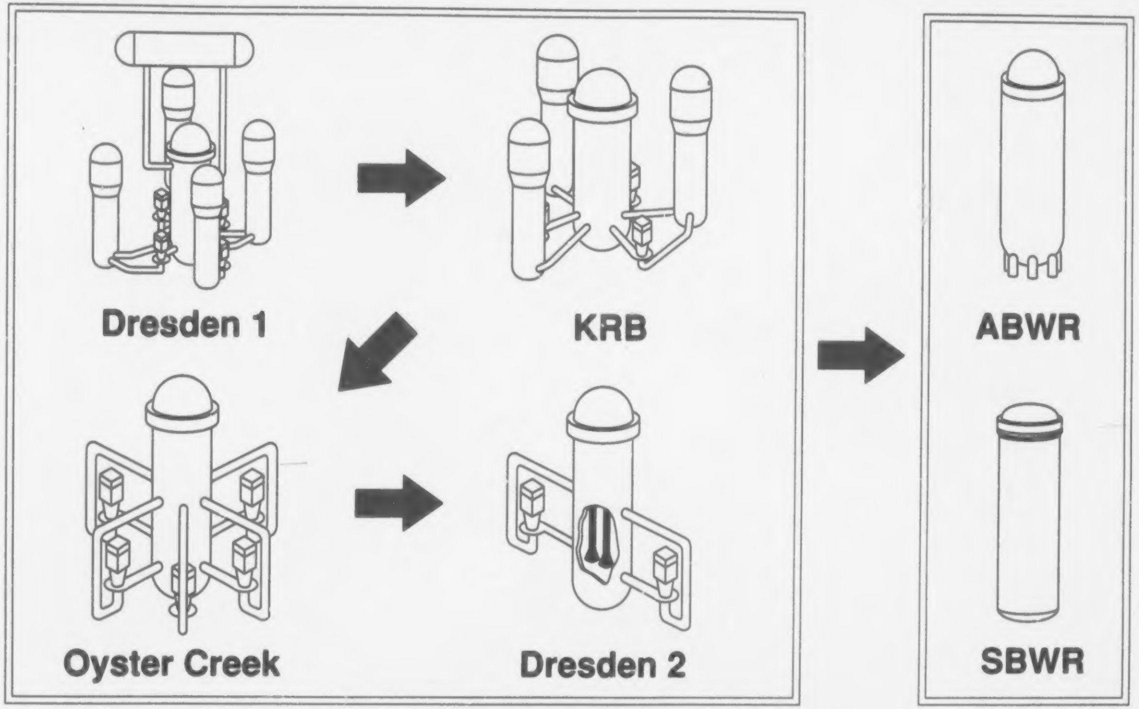
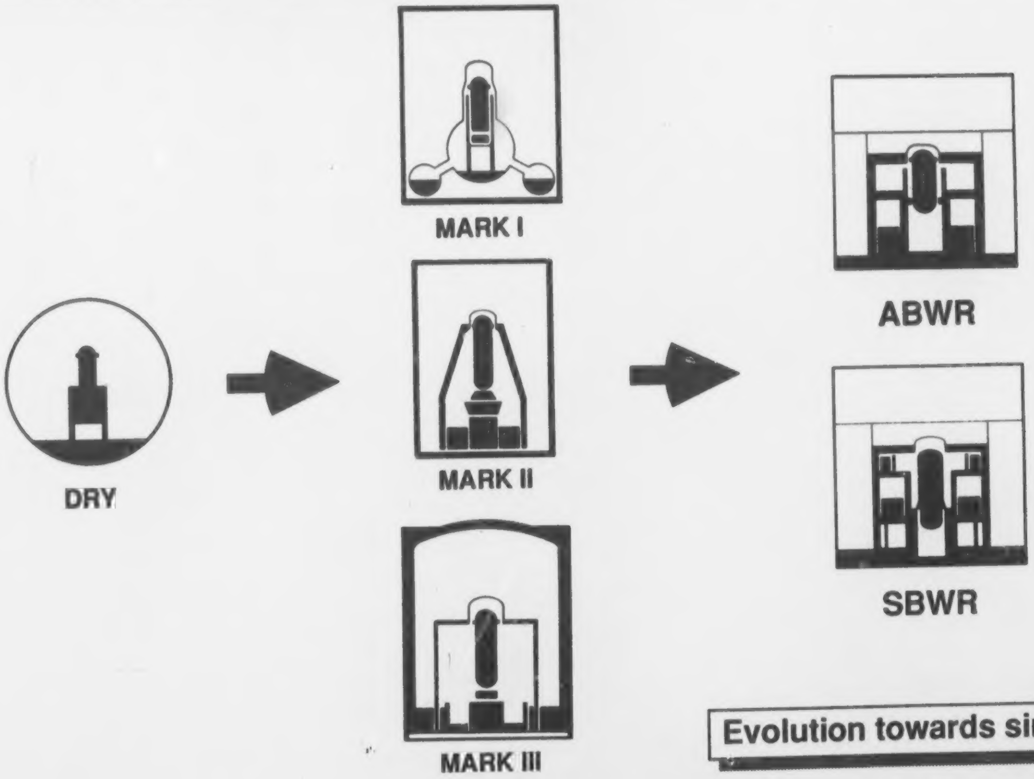
1. 1988/1989 data, operating plants
2. Rolling 4x10 basis
3. DOE methodology, 1990$

Evolution of the BWR Reactor Design


Dresden 1
KRB
Oyster Creek
Dresden 2
ABWR
SBWR

Evolution towards simplicity

Evolution of BWR Containment and Reactor Building Design


DRY
MARK I
MARK II
MARK III
ABWR
SBWR

Evolution towards simplicity

POST-HEARING QUESTIONS AND ANSWERS

JOSEPH M. FARLEY
PRESIDENT AND CHIEF EXECUTIVE OFFICER
SOUTHERN NUCLEAR OPERATING COMPANY

MARCH 5, 1991

ANSWERS TO QUESTIONS POSED BY SENATOR JOHNSTON

THE PROCESS LAID OUT IN TITLE XII

1. In his testimony, Mr. Young identifies three main problems with the provisions of Title XII -- that DOE is already doing most of the things envisioned under Section 12005; that it is too early to expect a utility to order a nuclear plant, even with the benefits of Section 12005; and that direct federal government participation in a demonstration project would be inappropriate.

   This is a fairly strong rejection of Title XII.

   a. Do you believe that DOE can do everything necessary to revive the nuclear option without any enforcement or encouragement by Congress?

Response: No. Reviving the nuclear option will require the combined and coordinated efforts of Congress, the nuclear power industry, and numerous state and federal regulatory agencies, including DOE. Congress, as a barometer of public will and public interest, must continue to exercise its leadership and oversight responsibilities to insure that appropriations are targeted to achieve quickly the re-emergence of nuclear energy. Without such endorsement and encouragement, the efforts of DOE and others will be seriously handicapped. For its part, DOE must remain very active in this endeavor. The most effective contribution it can make to preserve the nuclear option is to continue its research and development efforts in the ALWR program, including resolving first-of-a-kind engineering issues and site certification issues.

b. **What part of Title XII, if any, do you think would be helpful in ensuring that advanced reactor designs will be available when needed?**

Response: The principal goal of Title XII is to promote commercial operation of a nuclear plant utilizing an advanced reactor design. Title XII proposes to accomplish this goal by government participation in the construction phase and operation of the nuclear power plant. Southern Nuclear believes that the advanced reactor design closest to commercial operation is the ALWR. For this design, current DOE programs supporting design certification, first-of-a-kind engineering and site certification should continue independently of Title XII. Once those issues are resolved, and the NRC has certified ALWR designs for commercial operation, such success, coupled with Congressional reform of the licensing process and high-level waste issues, would make government participation in constructing and operating an ALWR unnecessary. Instead, the free market system should determine whether an order for such an ALWR will be placed.

For other advanced reactor designs such as the MHTGR, government participation in a demonstration plant may very well be needed. At Southern Nuclear, we believe that an MHTGR will become a commercial candidate only after several years of performance as a demonstration project and the completion of enough fuel cycles to provide high assurance of economic performance and material suitability for the long term. More specifically, we would want to see at least two fuel cycles of twenty months each for an MHTGR to assure us that the fundamental fuel design, manufacturing and operational integrity are adequate. Moreover, we note that although the MHTGR concept has a bright future as a viable application of an advanced reactor design making it deserving of continuing development, we currently do not believe such a design could be available to evaluate and possibly order until some undetermined year after 2005.

Consequently, Title XII's objective of promoting an advanced reactor design such as the MHTGR through government participation in a construction project should be started after 1995. The priority should remain with pursuing design certification, site planning, first-of-a-kind engineering, licensing reform and resolution of high-level waste issues for an ALWR.

c. What could be done to make Title XII more useful?

Response: Because we believe that the advanced reactor design most susceptible to the programs established by Title XII are the MHTGR and the LMFBR, we recommend that the legislation be made clear that it applies only to these types of unproven commercial technology. Focusing Title XII on continued support for ALWR programs resolving the issues identified above would also be a useful indication of Congressional concern over the future of nuclear energy.

2. **You also expressed concern in your testimony about the process laid out in Title XII, in particular the concern that federal participation in a construction project would divert funds from other valuable R&D. The authority in Title XII is intended to be in addition to and independent of ongoing R&D programs.**

   a. **Would your concerns about Title XII be diminished if it was clear that a demonstration project would not reduce the available funds for existing R&D programs?**

Response: Yes, my concerns about the timeliness of Title XII would be diminished if it was made clear that no reduction of funding for existing ALWR research and development programs would occur. Nevertheless, I would still have some concern that any funding for a program under Title XII would inevitably result in reduction of much needed funding for other activities more likely to result in the re-emergence of the nuclear option since we cannot help but be aware of the enormous budgetary constraints under which the Congress must operate.

   b. Would you then support a demonstration such as envisioned in Title XII?

Response: If no funding reduction occurs in the ALWR programs and if the goals of Title XII were focused on advanced reactor design such as the MHTGR, then Southern Nuclear would support such a demonstration project.

c. Why wouldn't it be attractive to a utility to participate in a demonstration project that received 50% federal funds?

Response: The initial, and natural, reaction to a federal cost-sharing program which provides 50% funding for an advanced reactor design demonstration project is favorable. Regretfully, however, the experience of the industry in the Clinch River project has left considerable concern about the viability of such a partnership. At Southern Nuclear, we believe that with successful completion of standardized design, NRC licensing reform and high-level waste storage progress, the ALWR program will not need governmental participation because of the wide acceptance this proven technology has enjoyed in the nuclear power industry. It may be attractive for a utility to participate in a demonstration project contemplated by Title XII, but to determine the attractiveness of this participation, and to gauge the willingness of a utility to invest in it, would require much more detailed evaluation of the project.

d. Similarly, why wouldn't it be attractive to a utility to participate in a project under Section 12005, the so-called institutional demonstration?

Response: Problems of investment recovery through the ratemaking process, financing and joint operational responsibility between a utility and the United States Government discourage utility participation in the institutional demonstration described in Section 12005. As we have noted earlier, we believe that the ALWR design is likely to be a better investment for base load capacity than other competing options available to a utility. In my opinion, the first several orders would be placed by groups of utilities that share both the financial burden and the energy output from such a plant.

UTILITY PARTICIPATION IN A DEMONSTRATION PROJECT

3. Last year, DOE offered to assist a utility to obtain a license as part of a demonstration project, but got no volunteers. Why was there so little interest among the utilities in this program?

Response: I believe that this question refers to the earlier site certification Request for Quotation that DOE promulgated last fall. There was a great deal of interest among utilities for this program and, currently, several utilities are undertaking to prepare a proposal that would be responsive to DOE's request. The DOE site proposal appeared to include immediate activity such as public hearings on proposed emergency plans at this early time when a responding utility would not know whether, in fact, an ALWR design would be available in 1995 or whether licensing reform would have taken place, and, yet, all the public problems with siting a new facility would be discussed prematurely and opposition generated well before the need for power or the opportunity to proceed arose. Nevertheless, work is currently underway on this effort to respond to the RFQ but would not involve committing a utility to a public announcement that it intends to order a new nuclear plant.

FUTURE ORDERS OF NUCLEAR PLANTS

4. How much of the estimated 150 to 250 gigawatts of new electrical capacity needed over the next two decades do you expect will be supplied by nuclear power?

Response: Any response to this question depends upon the resolution of identified problems with the re-emergence of the nuclear option such as the development of a standardized design, licensing reform and high level waste problems. If such problems are resolved, then an ALWR nuclear plant, probably a mid-sized one, will likely come on line in approximately 10-12 years. The current over-supply of baseload generation is ending and demand during the intervening period can be satisfied by short-term peaking and intermediate generation. However, beginning in the early part of the 21st Century, with the resolution of current nuclear energy problems, there exists a very real possibility that over 50% of new baseload generation ordered after the year 2000 will be nuclear. As a percent of total gigawatts of new capacity to be added from 1991 through 2011, in this country, this new nuclear capacity will probably only account for 5-10%. The size of this number reflects the large number of combustion turbines and other fossil capacity that will come on line before it is possible to bring on nuclear units ordered after 1995.

5. What portion of these orders do you expect to be --

1,300 megawatt so-called "evolutionary" LWRSs

600 megawatt so-called "advanced passive" LWRs?

Modular high temperature gas reactors?

Liquid metal reactors?

Response:

1,300 megawatt evolutionary LWRs:	approximately 10%
600 megawatt ALWRs:	approximately 90%
MHTGR:	0%
LMFBR:	0%

This answer does not reflect on the eventual bright future for advanced MHTGR and LMFBR technology but only on the time frame for commercialization. In addition, please see my answer to Question 1(b) above and the EPRI research project report on MHTGR attached to these answers.

QUALITY AND FOCUS OF DOE'S R&D PROGRAMS

6. Do you believe that DOE's R&D programs have improved over the last couple of years?

Response: Yes. DOE is becoming more responsive to the realities of the commercial marketplace and is supporting the kind of R&D programs that will be most beneficial to reactor designs likely to benefit the greatest number of electric utilities.

7. Are these programs better focused now than in past years?

Response: Yes. In addition to my response to Question 6, commendation is due DOE for its attentiveness to the kinds of concerns that system generation planners and utility managers have been expressing for a number of years. It is clear from this focus that DOE shares our belief that re-emergence of the nuclear option is vital to the energy security of the United States and that existing impediments to such a re-emergence -- such as powerplant design, licensing, and waste disposal -- must be resolved.

QUESTIONS FOR ALL WITNESSES FROM SENATOR WALLOP

1. The Department of Energy estimates that a combination of increases in demand and retirement of existing electric generation capacity will require an additional 200,000 megawatts of capacity by the year 2010.

   a. Would you agree with Mr. Wolfe's statement that until recently there has been considerable excess electric capacity in this country but this era is coming to an end?

Response: While I would not describe the situation as "considerable excess electrical capacity," I would acknowledge readily that reserve margins have been somewhat higher than is traditionally thought necessary. Due in large part to the Arab Oil Embargo of 1973, the United States has experienced a dramatic decrease in load growth from an historical 7% annual growth rate to a 1%-3% annual growth rate. This demand reduction resulted in cancellation or delay of many baseload generation plants. As completion of these large generating stations occurred, some oversupply of capacity existed in some areas of the country. Now, however, reserve margins in many parts of the country are dropping to a level that is either at minimum or below the level desirable for reliable electric service. Projections by virtually every load forecasting technique point to the need for baseload capacity by the end of this century.

b. Faced with today's environmental laws such as the Clean Air Act, in your judgment, can this requirement for new generation capacity be satisfied without a greater role for nuclear power than is possible under present circumstances?

Response: I believe it will be difficult to reconcile the Clean Air Act requirements and the growing pressure from many sources on global warming with supplying increased generating capacity only from fossil fuels. In the next century, the price of natural gas will doubtless also be substantially increasing. While it may conceivably be possible to meet these demands with fossil fuels, and live within statutory and regulatory requirements, the price would be high, and, in my judgment, nuclear energy would provide a much better solution for a substantial part of that future generation need.

c. In your judgment, can the third world meet its anticipated requirements for electricity without a large expansion of nuclear power?

Response: If the third world does not have the nuclear power option, its only way to respond to its urgently growing energy need will be through the burning of fossil fuel. However, the present experience around the world would indicate that such generation would be at the expense of the environment unless these nations apply our standards of environmental care, which is unlikely. If it does not, then large quantities of SO_2, nitrous oxide, and CO_2, (in addition to particulate matter) would be involved on a global basis and our country may very well be denied the advantages of the massive investment required by the Clean Air Act.

2. a. Would you agree that the long-term promise of nuclear energy is an essentially unlimited through the development of advanced liquid metal reactor technologies?

Response: The development of the ALMR technology is very promising. I do believe its commercial availability is sometime in the future, however, and that ALWR technology is much closer to being ready for commercial use. I would support ongoing LMR Research & Development, and my only concern would be that it not distract from the ALWR program which is a more promising opportunity for the near future.

b. In your judgment should DOE's program be more aggressive in this regard?

Response: DOE is focusing available resources on the ALWR which, I believe, should have the first priority. I agree with DOE's support of this technology, but I believe that the LMR and MHTGR should not be summarily neglected.

3. Institution problems are often cited as the reason why we cannot build nuclear power plants in the United States. Japan and France are often used as examples of it taking only four to six years to build a nuclear power plant and put it into operation.

a. Why is this the case in Japan and France? If I am correct these countries rely on a licensing system similar to that in the United States. Would you comment?

Response: I believe that the premise is not correct that Japan and France have a similar licensing system. I believe that the multitude of changes constantly required by the NRC, as well as legal delays possible through such obstacles as post-construction hearings, are a U.S. phenomenon. In fact, when I participated in a seminar several years ago in Japan with its nuclear leadership, the description of our licensing process so amazed them that they thought the interpreter had mistranslated our description. This is the reason that we must have licensing reform. In France, the standardized design has been most helpful and is, I believe, a future part of what should be our institutional system. One must remember in this regard that the Japanese and French were not inhibited by antitrust concerns or local rate regulations which required so much arm's length activity in the U.S. and a continuing necessity for competitive bids with each order.

b. Are standardized designs critical to expediting this process?

Response: The importance of the existence of a certified standardized reactor design, with known and measurable engineering requirements, cannot be overstated. History has proven that the design-as-you-go philosophy results in vast construction cost overruns and subsequent disallowance for ratemaking purposes of billions of dollars as well as lengthy and costly delays in construction.

4. Public confidence in the nuclear power option is essential if it is to play a role in our nation's energy future.

a. Passive safety features are critical to the public's acceptance of nuclear power. Would you agree?

Response: I believe passive safety features are important in helping raise public acceptance. However, I believe a continued record of safe plant operations will also greatly enhance public acceptance of nuclear power.

b. In your judgment, do liquid metal reactors and high-temperature gas-cooled reactors have advantages with regard to passive safety features?

Response: I am not sure that we are far enough along with LMR and MHTGR technology to be fully certain as to the actual advantages on passive safety over the ALWR passive designs. Certainly, in theory they are even safer. I have attached a copy of a critique of the MHTGR prepared by EPRI and utility reviewers which I believe helps illustrates this point.

c. If we are concerned for the future of nuclear power, would you agree that there is a need for a more active Federal support for these technologies in addition to "advanced" light water reactors?

Response: At Southern Nuclear, we believe that for the foreseeable future the re-emergence of nuclear energy is dependent on the ALWR design. With R&D support for this technology, our nation will be positioned to enjoy its many benefits beginning in the early 21st Century. Other advanced reactor designs, such as the MHTGR, are deserving of active federal support.

However, I am aware of Federal budget constraints which is why I would urge that the first priority be given to the ALWR design certification and first-of-a-kind engineering with R & D on other technologies to follow.

5. Would you agree that the future of the nuclear power industry rests in the development of advanced nuclear reactor designs and streamlining the regulatory structure of bringing on line new, safer generations of nuclear reactor technologies?

Response: In summary fashion, at Southern Nuclear we believe that the future of nuclear energy rests in achieving the following goals:

-- Certification of a standardized advanced light water reactor design, preferably, in our case, a mid-sized, passive one;

-- Resolution of high-level waste issues;

-- Completion of first-of-a-kind engineering associated with an ALWR certified design;

-- Reform of the current two-step licensing procedures to a one-step process with no required pre-operational hearing such as we have proposed in our testimony; and

-- Resolution of site certification issues.

Once this occurs, we believe the free market will determine whether or not an ALWR is ordered, a determination which will be based on the economics of such a transaction. We believe that determination will be positive.

QUESTIONS FOR UTILITY WITNESSES

FROM SENATOR WALLOP

A. Much has been said about the need for this legislation if nuclear power is to play a role in our nation's energy future. Let us assume that the legislation before us is passed and accomplishes all that is intended regarding licensing reform and the NRC's certification of advanced reactor designs.

a. What are the plans of each of your utilities regarding new nuclear electric generation capacity?

Response: The Southern electric system currently has no specific plans to order a new nuclear power plant. However, under our current integrated generation resource plan, we show a need for 800 megawatts of baseload generation soon after the turn of the century, with other additions to follow in succeeding years. The Southern electric system greatly desires to have available to it the option to use nuclear power to meet its growing baseload requirement and subsequent baseload capacity needs. We are prepared to consider seriously nuclear as an alternate to, or in addition to, fossil burning plants.

b. What would be required for each of you to place an actual order?

Response: Naturally, the predicate to answering this question assumes competitive pricing of a nuclear power plant as well as the requisite load growth mandating a need for additional baseload generation. The requirements to place an actual order that need Congressional support are:

-- Additional support and encouragement for resolution of high-level waste issues, which may necessitate legislation;

-- License reform - as we have proposed in our suggested changes to Title XIII of S. 341.

-- Continued appropriations support and encouragement for completion of a certified standardized ALWR including the necessary first-of-a-kind engineering.

In addition to these matters, of course, we must perceive a receptiveness by our ratepayers and stockholders to the commitments associated with purchasing a nuclear power plant. This is particularly true in the case of our economic regulators who will be asked to determine the rate structure which would result in both a return of and a return on the investment for any baseload addition.

ANSWERS TO QUESTIONS POSED BY SENATOR WALLOP

The licensing provision in the bill is intended to strike a balance between the need for public participation in determination of safety issues and investor security. From your perspective, how should public participation mesh with the requirement for predictability in licensing?

Response: Public participation in the licensing process of any new nuclear power plant is very important. An integral component of the re-emergence of nuclear power is public confidence and continued safe operation of existing plants and extension of this safety record to new plants. These are the kinds of issues which will be raised, and resolved, at the initial hearing and thus those interested persons directly affected by the plant should have a process available to air their concerns and suggestions. At Southern Nuclear, we believe that public participation should occur early in the licensing process, when it can be meaningful and constructive. By identifying public concerns early and resolving them, predictability in nuclear power plant licensing can be achieved. It is important, however, that once these issues are resolved that they be respected and not changed unless there is clear, compelling evidence that the earlier decision poses a significant hazard to public health and safety.

The natural result of giving the public a full and fair opportunity to raise all its concerns at the start of the construction project, resolving those concerns and according such resolutions the weight of other regulatory decisions, will be to inject predictability in the licensing process because all concerned will be motivated to identify every disputed issue and then vigorously advocate a solution. In general terms, this issue resolution model is the same as utilized by our judicial system for the last two hundred years. Public confidence, public perception of fairness, and regulatory stability would be well-served by following this model. Other nations, such as Japan and France, have such stability.

Your testimony implies that additional language or other changes in drafting might be desirable to insure that the licensing provisions expressly address the recent U. S. Court of Appeals decision invalidating a part of NRC's Part 52 licensing regulations. Could you please elaborate on that point?

Response: In my testimony I noted that the drafters of Title XIII had commendable objectives shared by many who well-recognize the abysmal results occasioned by the existing licensing procedures. Attached to my answers is proposed legislation which we believe is responsive to the concerns expressed in the U. S. Court of Appeals decision in Nuclear Information and Resource Service v. U. S. Nuclear Regulatory Commission, 918 F.2d 189 (D.C. Circuit, 1990), and also provides for a streamlined one-step licensing process which eliminates artificial and unneeded procedural delays in licensing.

NRC adopted its "realism rule" in 1987 to address emergency planning. Why do you feel it would be necessary to specifically address emergency planning in this legislation?

Response: Southern Nuclear feels that emergency planning issues can be identified at the initial hearing prior to granting the combined license. Then, appropriate acceptance criteria can be designed so that the applicant, the public, and the jurisdictional agencies know exactly what needs to be done in this area to operate the plant. With pre-certified designs there will no longer be "unknowns" which would affect emergency planning. Without such an early, clear resolution of emergency planning issues, the opportunity for construction and licensing efficiency will be lost. Uncertainty will substitute for stability and the past practice of design-as-you-go decision making will prevail. This is poor public policy and should not be repeated.

TITLE XIII - NUCLEAR REACTOR LICENSING

SEC. 13001. SHORT TITLE

This title may be cited as the "Nuclear Reactor Licensing Act of 1991.".

SEC. 13002. REACTOR LICENSING

Section 185 of the Atomic Energy Act of 1954 (42 U.S.C. 2235) is amended by:

(1) adding "and Combined Construction Permits and Operating Licenses" after "Permits" in the catchline;

(2) adding a subsection designator "a. Construction Permits" before "All"; and

(3) adding the following new subsection:

"b. Combined Construction Permits and Operating Licenses

(1) In the case of an application under subsection 161h. for a combined license to construct and operate a production and utilization facility, the Commission shall hold a hearing as described in Section 189a.(1) prior to granting the combined license.

(2) The Commission shall identify within the combined license all of the inspections, tests and analyses that the licensee shall perform, and the acceptance criteria, including those applicable to emergency planning issues, that the Commission shall use to provide reasonable assurance that the production and utilization facility will be constructed and will operate in conformity with the provisions of this Act.

(3) Combined licenses shall be amended in the same manner as licenses issued under Section 103 of this Act.

(4) Upon completion of construction of the facility in conformance with the combined license, as amended, commercial operation may proceed without further action by the Commission.

(5) Before commercial operation begins, any interested person contending that the facility either has not been constructed, or will not operate, in accordance with the combined license may request a hearing. The Commission shall deny such a request for a hearing unless it finds that:

(a) A prima facie showing has been made by substantial evidence that one or more of the acceptance criteria in the combined license have not been met and that this deficiency will result in a significant hazard to public health and safety; and

(b) There is a genuine issue of material fact that neither has been, nor could have been, previously considered by the Commission, nor can it be resolved by any other means except a hearing.

(6) Any hearing held under subsection (5) above shall be limited to issues of non-conformance with the combined license and

the interested person so contending bears the burden of proving same. The pendency of any such hearing or request for hearing shall not delay commercial operation of the facility.

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Topics:
Nuclear power plants
Reactor designs

EPRI NP-7135
Project 2079
Final Report
January 1991

A Utility Assessment of the Modular High-Temperature Gas-Cooled Reactor (MHTGR)

Prepared by
Commonwealth Edison Company
Duke Engineering & Services
Yankee Atomic Electric Company
and
Duke Power Company

REPORT SUMMARY

SUBJECT	Advanced nuclear systems	
TOPICS	Nuclear power plants	Reactor designs
AUDIENCE	Generation engineers / R&D planners	

A Utility Assessment of the Modular High-Temperature Gas-Cooled Reactor (MHTGR)

A team of three nuclear utilities evaluated the current MHTGR conceptual design from the viewpoint of potential owner/operators. The specified focus of the evaluation includes a definitive assessment of the MHTGR's strengths and weaknesses, prospects for successful licensing and for utility deployment, and recommendations addressing necessary R&D.

BACKGROUND The MHTGR is a high-temperature gas-cooled reactor design developed as part of the DOE advanced reactor program. The design is intended to incorporate many passive safety features that require neither operator action nor reliance on backup ac power to function.

OBJECTIVE To provide the utility industry with an evaluation of the current MHTGR design from the viewpoint of potential owner/operators.

APPROACH The evaluation team reviewed available MHTGR design, licensing, and progress documentation and attended technical presentations made by the MHTGR program participants.

RESULTS The utility team concluded that the current MHTGR conceptual design is a viable nuclear option for the power industry for the coming century and deserves continuing development. This endorsement is consistent with recent assessments provided by the utility industry. The passively safe response of MHTGR to off-normal events accomplishes safety functions without reliance on either operator action or backup ac power and with the spinoff benefit of minimal required maintenance of safety equipment. The design also promises to achieve extremely low personnel radiation doses.

Key R&D needs identified are establishing the fission-product retention capability on the fuel, achieving a consensus on the degree of containment required, and achieving economic competitiveness with contemporary versions of the LWR. The team made several recommendations aimed at meeting these needs and improving the appeal of the design to potential owner/operators.

EPRI PERSPECTIVE The utility team has conducted a thorough and independent evaluation of the current MHTGR design and has reached conclucions and recommendations that are well supported in the evaluation report.

PROJECT RP2079
EPRI Project Manager: Ed Rodwell
Nuclear Power Division
Contractors: Commonwealth Edison Company; Duke Engineering & Services; Yankee Atomic Electric Company; Duke Power Company

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A Utility Assessment of the Modular High-Temperature Gas-Cooled Reactor (MHTGR)

NP-7135
Research Project 2079

Final Report, January 1991

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ABSTRACT

A team of electric utility representatives conducted an in-depth, independent evaluation of the current Modular High Temperature Gas-Cooled Reactor (MHTGR) design. The emphasis was on the fuel design with respect to safety, the licensability of the proposed containment concept, refueling operations and equipment, spent fuel storage capacity, staffing projections, and the economic competitiveness.

Specific comments and recommendations are provided as a contribution towards enhancing the MHTGR design, licensability and acceptance from a utility 's view.

EPRI FOREWORD

EPRI sponsored three nuclear utilities in an evaluation of the current modular high-temperature gas-cooled reactor (MHTGR) design from the viewpoint of potential utility owner/operators. The specified contents for the evaluation report included a definitive assessment of the MHTGR's strengths and weaknesses, prospects for successful licensing, prospects for utility acceptance and deployment, and recommendations addressing the near- and long-term R&D necessary to ensure successful licensing and deployment. The evaluation was required to address, but not be limited to, the main issues raised in the EPRI report specific to the MHTGR (report NP-6676) resulting from a 1987-88 utility industry team evaluation of the nation's advanced reactor designs.

The MHTGR is a high-temperature gas-cooled reactor design developed as part of the DOE advanced reactor program. The main participants in the design team are Bechtel, Combustion Engineering, General Atomics, and Stone & Webster, with R&D support by Oak Ridge National Laboratory. Prospective owner/operator input to the design is provided by Gas-Cooled-Reactor Associates.

The Utility Review Team consisted of eight representatives from three utilities. Independence in the evaluation was achieved by assigning the evaluation to utilities that do not currently participate in the MHTGR development program. The independent evaluation was supported by additional utility contributions from Philadelphia Electric Company and Public Service of Colorado in the form of reports summarizing their MHTGR operating experience. The members of the utility review team are listed below:

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The method of conducting the evaluation consisted of reviewing presently available MHTGR design, licensing, and progress report documentation and attending technical presentations made by the MHTGR program participants. Appendix A is a composite listing of all MHTGR documentation provided to the utilities before and during the evaluation process. Following review of that documentation, the Utility Review Team identified, in question format, those subtopics on which more information or discussion was needed to enable the review team to complete their evaluation. The questions were provided to the MHTGR participants, who provided associated technical literature and attended a four-day meeting that included presentations and discussions with the Utility Review Team. Appendix B is a copy of the agenda for the four-day meeting.

Following the meeting, the Utility Review Team developed draft evaluations of the information provided in their respective assigned areas. Commonwealth Edison had lead responsibility for the economic competitiveness evaluation. Yankee Atomic was lead on the fuel design evaluation. Duke Power was lead on containment licensability, spent fuel, refueling, and staffing evaluations. The drafts were exchanged among the Utility Review Team members. Meetings were held to integrate the drafts into a preliminary report and to agree upon conclusions and recommendations from the team. The integrated preliminary report was then reviewed by Philadelphia Electric Company, Public Service of Colorado, Consumers Power, and the MHTGR participants, coordinated by the Plant Design Control Office. Comments given to the Utility Review Team were reviewed and incorporated as the review team considered appropriate.

Ed Rodwell, Project Manager
Nuclear Power Division

ACKNOWLEDGMENTS

The Utility Review Team appreciates the efforts of all MHTGR Participants who provided detailed presentations and reference material in response to the utilities' technical questions at the May 7 to May 10, 1990 meeting in San Diego.

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Section 1

EXECUTIVE SUMMARY

1.1 Introduction

A team of electric utility representatives (Utility Review Team) conducted an in-depth independent evaluation of the Modular High Temperature Gas Reactor (MHTGR) design. The emphasis of the review was on the fuel design with respect to safety objectives, the licensability of the proposed containment concept, refueling operations and equipment, spent fuel storage capacity, staffing projections, and the economic competitiveness compared to contemporaneous designs. This review, at the request of Electric Power Research Institute (EPRI), addressed the main issues raised in an earlier report (August, 1989) titled Utility Industry Evaluation of the Modular High Temperature Gas Cooled Reactor (EPRI Report NP 6676). In each of the assigned topics, the Utility Review Team considered the MHTGR's strengths and weaknesses, the prospects for successful licensing, the prospects for utility acceptance and deployment, and the current research and development programs in support of MHTGR design and licensing activities. This section provides a summary of the main conclusions and recommendations that are explained in more detail in the subsequent sections.

1.2 Strengths and Weaknesses

The unique MHTGR radionuclide control concept takes full advantage of many inherent, passive safety features of the MHTGR fuel and core design. A very large fraction of fission products are retained by several barrier mechanisms. The primary barrier to fission product release is the fuel particle with its thermally resistant and impermeable pyrolytic carbon and silicon carbide coatings. A non-defective fuel particle will contain nearly all of the fission products where they are generated. The second barrier consists of the fuel matrix and the graphite moderator blocks through which the fission products must migrate. The third barrier is the closed primary coolant system boundary consisting of the reactor vessel, crossduct and steam generator. The fourth barrier is the reactor building. Although this is a low-pressure, non-leak tight structure, some credit is taken for radionuclide holdup and plateout for certain postulated accidents to meet the top-level requirements summarized in Table 2.2.1. The MHTGR Participants postulate that a very small fraction of fission products will be released into the primary coolant system during normal operation provided the fuel temperatures are maintained below 1330 °C, and therefore, it is likely that the primary coolant system will have minimal contamination levels.

The pure helium coolant of the primary system is inert so that no chemical reaction with the fuel or coatings is possible, provided air, steam, and other impurities are monitored and maintained to very small quantities to prevent their chemical attack on the fuel and coatings. Pure helium does not produce any significant reactivity effects. Flashing or boiling of the pure helium coolant is not possible. Coolant level measurements are not required.

The annular core configuration and other core physics characteristics provide a negative temperature coefficient under all operating conditions. In addition, the annular core combined with the low core power density and the uninsulated steel vessel, allow for passive decay heat removal by conduction, convection, and radiation through the Reactor Cavity Cooling System to the ultimate heat sink during limiting events.

In summary, the above described passive safety features are intrinsic to the MHTGR design. They require neither operator action nor reliance on backup AC power to accomplish the safety functions. The same features offer the prospects of simplified plant operations, and a slow, stable response for the reactor to mismatches in heat generation and removal. The lack of dependence on active safety equipment together with fewer safety related components offers the potential for easier satisfaction of regulatory operational and maintenance requirements compared to today's Light Water Reactor (LWR) plants. In addition, the MHTGR design is radiologically cleaner with the potential for lower plant contamination levels, shorter outages due to reduced radiation levels, easier plant maintenance, lower personnel exposures, lower radwaste volumes to be disposed, and ultimately, an easier decommissioning. These features are considered to be very valuable and significant advantages from a utility perspective.

The MHTGR safety assessments conducted to date have evaluated a broad spectrum of events ranging from anticipated operational occurrences to postulated low probability accidents. The objective in each evaluation was to show that any release of radionuclides is controlled within the top level regulatory offsite dose limits. Assessment results to date support the MHTGR Participants' position that no public sheltering or evacuation plans are required beyond the plant exclusion area boundary for design basis events and events beyond the design basis. These results contain uncertainties that must be resolved by future development work if this position is to prevail.

While the unique MHTGR radionuclide control concept takes full advantage of many inherent passive safety features of the fuel and core design, the concept places a heavy burden on establishing and protecting the fission product retention capabilities of the fuel under all normal, off normal, and accident conditions. Secondary barriers provide some additional radionuclide retention, but these barriers are not specifically designed to carry out this function. Very stringent MHTGR fuel quality and performance requirements must be met by billions of microspheres of enriched uranium oxycarbide fuel particles to protect the public, plant personnel, and components throughout the plant lifetime. The viability of these high quality fuel and performance requirements on a commercial scale rests upon much technology that is currently not well established. Increased emphasis is placed upon the acccuracy, thoroughness and validation of the complex phenomena represented in the safety analysis codes, especially the fuel performance at high temperatures and fission product transport through all barriers. Emphasis is also placed on plant systems and components that must protect the fuel during all accident conditions. These systems and components must maintain fuel particle temperatures below 1700°C by controlling heat generation and heat removal from the fuel. The systems and components must also limit chemical attack from air, steam, water, or other impurities on the fuel for all initial and transient conditions addressed in the design safety analyses.

The present refueling plan for the MHTGR is to replace one-half of the core (approximately 330 hexagonal fuel elements) and one-sixth of the replaceable reflector elements (approximately 270 elements) every 20 months. A single refueling outage involves removing and replacing 1064 elements. This process must be accomplished without misloading or damaging the fuel. When compared to present LWR designs, this process appears significantly more complicated to accomplish while maintaining accurate inventories of the fuel blocks. This comparison is even more significant when comparing the quantity of fuel handling maneuvers of two MHTGR plants (with four modules each) to a single 1100 MWe LWR of today's vintage. Likewise, fuel management appears to be more complex than current LWR designs and can be further complicated by the potential of asynchronous operation of two MHTGR reactor modules paired to one turbine.

The MHTGR modular design (single turbine with two reactor modules) offers several potential advantages such as shorter lead times per module pair, shorter construction periods, incremental capital investments with earlier revenues, and incremental additions of system capacity better matched to system growth needs. Utilities will compare these modular advantages beyond the planning and construction stages to operation and maintenance considerations of increased refueling operations, more complicated fuel-management of multiple units, the overall management of multiple units, the potential cost (materials, resources, and lost revenues) of retrofits for multiple units due to regulatory or efficiency reasons, and the relative small output of power per module for capital cost investment when replacing the larger capacity units of today's vintage.

1.3 Prospects for Licensing and Utility Acceptance

The stated goals of the MHTGR Program are to provide safe, economical power that complies with top level utility/user and regulatory requirements as organized by the Gas Cooled Reactor Associates (GCRA) and the Department of Energy (DOE). Utilizing years of development, testing, and operation of the HTGR Programs, the MHTGR Participants have developed an innovative modular design taking full advantage of inherent, passive safety features associated with ceramic coated fuel particles, graphite core structures, and helium coolant. While taking full advantage of the passive safety characteristics, the MHTGR radionuclide control concept places a heavy burden on establishing and protecting the fission product capabilities of the fuel. Very stringent MHTGR quality and performance requirements must be met by billions of microspheres of enriched uranium oxycarbide fuel particles to accomplish this objective. Fuel manufacturing and quality control must maintain fuel quality throughout the life of the plant without a single programmatic breakdown. The viability of these high quality fuel and performance requirements on a commercial scale rests upon much technology that is not currently well established. This especially includes the analytical models and supporting data to license the fuel and the radionuclide control concept. The fuel and fission product technology development plan is comprehensive, but appears to be overly optimistic. Suitable fallback positions should be identified in the event a key program element yields an unexpected result. Many key technology development elements that are interrelated, or related to the preliminary design process are scheduled to run in parallel; and therefore changes in the preliminary design may invalidate parallel or supporting technology development. The current Technology Development Needs (TDNs) must be completed prior to NRC certification of the current design to successfully demonstrate the MHTGR concept and to assure utility acceptance. The scope of these TDNs includes (a) prototypical fuel performance data, (b) successful validation of fuel performance and fission product transfer models, and (c) establishment of measurable safety margins between the calculated peak fuel temperature and the fuel particle failure temperature limit.

The MHTGR safety assessments conducted to date support the MHTGR Program Participants' position that no public sheltering or evacuation plans are required beyond the plant exclusion boundary for design basis events and events beyond the design basis. These assessments provide the technical basis for the MHTGR Program Participants' position that no low leakage containment is required around the primary coolant boundary. These assessments contain uncertainties that must be resolved by future development work.

The NRC Staff has concluded in SECY-88-203 that with proper engineering analysis, judgement, and demonstrated performance, it is possible for advanced reactor designs (including the MHTGR) to achieve a level of safety equivalent to that of current generation LWRs without utilizing a non-mechanistic source term, conventional containment building, or traditional offsite emergency planning.

In reviewing the NRC Staff's draft Preapplication Safety Evaluation Report of the MHTGR design, the NRC's Advisory Committee on Reactor Safeguards (ACRS) reached essentially the same conclusion: (a) whether or not a conventional containment structure should be required remains as a major unresolved licensing issue, (b) no additional scenarios of reasonable credibility could be postulated for which an additional physical barrier would be required for public protection, and (c) any requirements to add a containment as further defense in depth against unforeseen and unforeseeable events would be arbitrary. This discussion is similar to what occurred in the early days of LWR development. The ACRS position was not unanimous. Three ACRS members stated that experience has shown that new reactor designs have technical unknowns, and therefore, did not recommend the MHTGR reactors for design certification without a more extensive external barrier. They indicated this barrier should consist of either a conventional containment structure or other appropriate mitigation systems.

The current MHTGR design is responsive to the NRC's Policy Statement on Advanced Reactor Concepts. It offers many passive safety features including decay heat removal, long operator reaction times, and insensitivity to incorrect operator actions. Whether or not a conventional containment or a confinement-type structure is required will continue to be a primary licensing issue with much debate between and utilization of resources by the regulators, MHTGR Participants, the industry, and the public. This issue currently appears to be at a stalemate. The resolution of the containment issue could have a significant impact on the capital and O&M costs; and therefore, should be a priority for the MHTGR Participants to have ample opportunity to consider alternate designs. Acceptance of the MHTGR by utilities will depend, to a great extent, on expected capital and O&M costs, as well as resolution of licensing issues such as the containment.

Looking beyond the containment licensing issue to the certification of the commercial MHTGR plant under 10CFR52, the NRC Staff and the ACRS apparently agree that a full scale demonstration plant will be required. Because of the technical uncertainties associated with a new reactor design and the lack of operating experience, this Utility Review Team concludes that a confinement structure providing enhanced and diverse fission product retention should be required for the First of a Kind (FOAK) plant to demonstrate the MHTGR technology. This confinement structure might not need to be a conventional unvented, high pressure, low leakage containment, but might be a confinement system/structure that provides a more robust external barrier than is currently proposed. The Utility Review Team also concludes that the eventual containment requirements of the Commercial MHTGR Replica Plant will depend on the outcome of the current TDNs and the operating experience gained from the FOAK demonstration plant. To provide additional confidence to the utility industry, the FOAK plant should be built and operated on a utility grid in a commercial environment.

The present refueling plan for the MHTGR is to replace one-half of the core and one-sixth of the reflectors every 20 months. A single refueling outage involves removing and replacing 1064 elements. This process, when compared to current LWR design, appears significantly more complicated to accomplish while maintaining inventories of the fuel blocks and assuring proper fuel management. The current design concept incorporates many years of equipment and procedure evolution, and takes full advantage of state-of-the-art robotics technology to provide a highly automated process; however, an average element will be handled six times during refueling. Due to this extremely large amount of element handling, the ability of the fuel handling equipment to perform as required would have to be thoroughly demonstrated for utility acceptance. The level of complexity in refueling the MHTGR is of concern since a single failure at any point in the refueling process has a potential to delay the refueling schedule and poses a potential impact on reactor availability. The Utility Review Team recommends that the MHTGR Participants evaluate the incremental costs to provide redundant fuel handling equipment and associated plant conceptual changes to minimize the possibility of delays and to allow for concurrent refueling operations.

The present spent fuel storage capacity is based on the assumption that DOE will take possession of the spent fuel at the reactor site within one year of the time it was removed from the reactor under the provisions of the Nuclear Waste Policy Act of 1982. The one year storage capacity was also specified as a design objective by the GCRA Utility/User Requirements. With the federal government's inability to make visible progress toward either the permanent geologic repository or the Monitored Retrievable Storage facility, utilities have had to make provisions for onsite storage or face plant closure. It would be prudent, for a utility building a plant under current circumstances, to provide spent fuel storage for the expected useful life of the plant anticipating that newer plants would be the last to ship spent fuel to a government site. The Utility Review Team concludes that a utility choosing to build an MHTGR would not be prudent, nor likely, to incorporate only a one year spent fuel storage capacity.

The MHTGR concept incorporates many inherent passive safety features and offers a plant that potentially requires neither operator action nor reliance on backup AC power to accomplish safety functions. The same features offer the prospects of simplified plant operations, a slow, stable response of the reactor to mismatches in heat generation and removal, and the potential for fewer active safety systems. The MHTGR design is a radiologically cleaner plant than current LWRs with minimum contamination of the primary system resulting in the potential for lower plant contamination levels, easier plant maintenance, lower personal exposures, and lower radwaste volumes to be disposed. The MHTGR Participants have capitalized on these potentials for simplified operations and projected a plant staffing of 303 personnel for the replica MHTGR Commercial Plant. The Utility Review Team recognizes that the MHTGR projections are based on a more simple design than current LWRs, and that the MHTGR Participants are anticipating a more relaxed regulatory environment at the time of deployment. The MHTGR Program Participants are to be commended for aggressively pursuing ways to minimize staffing requirements. The yardstick of utility experience is with LWRs, and therefore, the Utility Review Team concludes that the current staffing projections are based on overly optimistic assumptions regarding workscope definitions, workforce utilization roles, and regulatory requirements. The Utility Review Team recommends that the staffing needs also be evaluated using the current regulatory environment and INPO guidelines. More consideration should also be given toward additional personnel in regard to investment protection. This additional evaluation should be performed as a follow up to the current nonconservative staffing assumptions to bracket the possible range of O&M and capital costs. The Utility Review Team supports the concept of an MHTGR Central Support Organization. The Review Team believes this concept should be developed and implemented in parallel with the MHTGR design and certification program. Specific attention should be directed at clarifying the charter, structure and functional scope for this organization.

One design objective of the MHTGR program is to maintain an economic advantage of at least 10 percent in the levelized busbar cost of electricity relative to a comparably sized, state-of-the-art, coal plant alternative. In literature published to date, the MHTGR generating costs have been favorably compared to comparably sized coal plants (pulverized and atmospheric fluidized bed) and PWRs using data from the Department of Energy Economic Database (EEDB). The Utility Review Team compared the MHTGR total generating costs, based on a commercial operation date of 2010, with a 550 MWe pulverized coal plant and the Westinghouse 600 MWe AP-600 Advanced Light Water Reactor Plant (ALWR) as two alternatives, reasonably representative of the marketplace in which the MHTGR will have to compete. The Utility Review Team recognizes that the published cost data used in this study may contain relatively large uncertainties due to the early stage of MHTGR and AP-600 design and to probable increases in environmental regulation affecting the pulverized coal plant. Based on the published data, and understanding that uncertainties exist, the Utility Review Team concludes that the MHTGR is competitive with (or slightly better than) the pulverized coal alternative and is not currently competitive with the AP-600 alternative. If a conventional, unvented, high pressure, low leakage containment structure is required for the MHTGR the economic competitiveness with the pulverized coal plant will be diminished, or lost entirely. Likewise the MHTGR would become even less competitive with the AP-600 alternative. A less costly containment alternative could probably be accommodated without affecting the economic competitiveness.

The Department of Energy has recently initiated a MHTGR cost reduction study. The Utility Review Team agrees with the need for this study and endorses its timely completion. A reduction in base construction costs of 20-25 percent is a reasonable target.

The deployment of future nuclear electric generation options is driven by the need of the utility industry to provide safe, economic, and reliable power due to load growth and economic development, and eventual retirement of older generating capacity. As confirmed by recent experience, future nuclear plants must have a predictable cost, schedule, and reliability in order to provide a realistic option for commercial electric generation. Based on the conceptual design and preapplication licensing review, the MHTGR offers a viable application of an advanced nuclear concept with many inherent passive safety features and simplified operational requirements. Until the Fuel Technology Development Needs have progressed further, the containment issue has been resolved, and the FOAK plant has been built and demonstrated, there are considerable uncertainties regarding the time period when the MHTGR would be available for commercial deployment. Based on industry reports, the Utility Review Team concludes that an optimum date for the MHTGR FOAK deployment is near the turn of the century. A period of time will be required to prove the principles and accumulate enough operating history to determine if the MHTGR can actually perform to expectations and provide safe, economic, reliable power with a predictable cost, schedule, and reliability. The Utility Review Team optimistically predicts the time frame for replica deployment to be in the years 2005 to 2010. In that time frame, the MHTGR must be economically competitive with state-of-the-art coal plants and LWRs with which the utility industry has much experience and for which there exists a worldwide support system. Industry reports estimate that Advanced LWR designs will be certified in the mid-1990s, without prototype testing, and could, therefore, have a one to two decade additional advantage of operating experience over the MHTGR. The LWR design will likely remain the dominant nuclear power technology and MHTGR's chief competitor for the next several decades. Utility acceptance and the competitiveness of the MHTGR design in that time frame will be measured as it is today; in terms of safety, economics, reliability, and predictable investment risks.

1.4 Research and Development Recommendations

The Fuel/Fission Product Technology Development plans, identified in Table 2.4-1, are comprehensive and appear to address most of the identified needs. The Utility Review Team recommends that certain areas be reexamined and priorities increased to strengthen the MHTGR technology base. Increased emphasis should be placed on development of the Quality Control process. The MHTGR fuel test range should be changed to 1200 - 2200 °C to clarify the high temperature fuel integrity limits. Increased emphasis should be placed on hydrolysis tests for depressurized core conduction cooldown conditions. Fuel performance tests should include power increases and decreases to simulate the extra fuel duty from the 150 load following events per core. The fission product transport R&D tasks should be reviewed to determine whether they will yield sufficient accuracy for and applicability to the MHTGR safety analyses.

Since key technology development tasks are scheduled to run in parallel, suitable fallback positions should be identified in case a key R&D task yields an unexpected result. Finally, a Licensing Analysis Plan should be developed that codifies how the future R&D results, together with residual uncertainties, will be used in the MHTGR safety analyses and licensing process.

The Utility Review Team concludes that the program scope for the Fuel Handling Equipment Research and Development (Design Data Needs (DDNs) M.34.13.01 through M.34.13.05) is adequate. The Review Team recommends that the selected design approach for each DDN be followed and completed on schedule. Use of the alternatives identified in Section 2 of each DDN should not be considered due to the potential impact on the schedule from unforseen problems.

1.5 Conclusion

In conclusion, the Utility Review Team recognizes that the MHTGR conceptual design offers a viable, potential nuclear option to the power industry for the next century and deserves continuing development. This endorsement is consistent with previous opinions expressed by the utility industry and more recently with the endorsement by the Advanced Reactor Corporation in the January 10, 1990 report by the Corporation's Ad Hoc Committee on DOE's Advanced Reactor Development Plan.

REPORT SUMMARY

SUBJECT Advanced nuclear systems

TOPICS Nuclear power plants Reactor design

AUDIENCE Fuels managers / R&D planners

Utility Industry Evaluation of the Modular High-Temperature Gas-Cooled Reactor

A team of utility industry representatives evaluated the modular high-temperature gas-cooled reactor (MHTGR) design being developed by a group led by General Atomics under DOE sponsorship. They concluded that the gas-cooled design is a viable application of an advanced nuclear concept that deserves continued development. This report provides comments and recommendations to help enhance the applicability of the MHTGR design for utility systems.

BACKGROUND The U.S. gas-cooled reactor program was initiated in the late 1950s with the development of design concepts based upon earlier work in the United Kingdom. Two high-temperature plants have been constructed and operated in the United States: the 40-MWe Peach Bottom plant, completed in 1967 and operated until 1974, and the 330-MWe Fort Saint Vrain plant, completed in 1974 and scheduled for defueling/decommissioning in 1990. U.S. electric utilities have consistently endorsed the development of the high-temperature gas-cooled reactor (HTGR). Currently the U.S. program is focusing on the development of a four-module, 540-MWe plant that emphasizes the enhancement of passive safety characteristics. In this study, senior representatives from nuclear power utilities teamed up, with support from EPRI staff and industry consultants, to evaluate the MHTGR design.

OBJECTIVE To provide the utility industry with an evaluation of the modular high-temperature gas-cooled reactor concept, as part of a broader evaluation of the nation's advanced reactor concepts.

APPROACH The MHTGR team made a two-day design presentation to the evaluation team, July 12–14, 1988. Approximately one month before the presentation, the MHTGR team provided the evaluation team with a package of advance reading material. Following the presentation, the comments and recommendations of evaluation team members were compiled by subject and documented. The main conclusions and recommendations were then summarized.

RESULTS The evaluation concluded that the MHTGR team has developed a plant design that offers several attractive characteristics, especially in the area of safety. The most significant safety feature is the nonreliance on plant protection systems to provide a passively safe response even to severe accidents in which the reactor shutdown system is assumed to fail. This enhanced safety feature may justify a premium in the busbar costs, yet the MHTGR must continue to strive for competitive busbar costs with those of other nuclear and coal-fired systems. One design feature, however, which may have to be reviewed to assure regulatory and utility acceptance, is the use of coated-particle fuel as the primary barrier in the MHTGR containment system. Until the fuel demonstration program has progressed further, some uncertainty remains that these particles can be manufactured and inspected on a commercial basis to the quality required and that they will consistently meet integrity requirements under severe accident conditions. Overall, the evaluation team's assessment of the MHTGR concept was very positive and called for further development.

EPRI PERSPECTIVE The evaluation team's positive assessment of the MHTGR design underscores the need for its continuing development. This is one in a series of EPRI reports addressing technologies associated with alternative reactor systems and designs that are part of the DOE advanced reactor program. EPRI report NP-6647 reviews the metal fuel concept being developed by Argonne National Laboratory; EPRI report NP-6644 reviews the power reactor inherently safe module (PRISM) plant design being developed by General Electric; and EPRI report NP-6633 reviews the sodium advanced fast reactor (SAFR) plant design being developed by Rockwell International.

PROJECT RP2079
EPRI Project Manager: Ed Rodwell
Nuclear Power Division

For further information on EPRI research programs, call EPRI Technical Information Specialists (415) 855-2411.

Utility Industry Evaluation of the Modular High-Temperature Gas-Cooled Reactor

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NP-6676
Research Project 2079

Final Report, February 1990

Prepared by

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ABSTRACT

A team of utility industry representatives evaluated the Modular High Temperature Gas-Cooled Reactor plant design, a current design created by an industrial team led by General Atomics under Department of Energy sponsorship and with support provided by utilities through Gas-Cooled Reactor Associates. The utility industry team concluded that the plant design should be considered a viable application of an advanced nuclear concept and deserves continuing development. Specific comments and recommendations are provided as a contribution towards improving a very promising plant design.

FOREWORD

The Modular High Temperature Gas-Cooled Reactor (MHTGR) plant design was evaluated in accordance with a utility industry plan (Appendix A) to assess the major advanced nuclear systems plant designs from the viewpoint of a potential electric utility owner-operator. An evaluation team, consisting of eight senior representatives of nuclear utilities was established with support from seven EPRI staff members and consultants. The personnel in this team are identified in Appendix A. The MHTGR is a high temperature gas-cooled reactor design created by General Atomics (GA), supported by several other plant and equipment suppliers as part of the Department of Energy's (DOE) advanced reactor program. Utility support and prospective owner input to design and licensing is provided by utilities through Gas-Cooled Reactor Associates (GCRA).

The centerpoint of the evaluation process was a two-day design presentation by the MHTGR project, given to the utility evaluation team on July 12-14, 1988. The agenda requested for the presentation is identified in the Appendix A plan. Approximately one month before the presentation, the MHTGR project provided the evaluation team with the package of advance reading material identified in Appendix B.

Following the presentation, the evaluation team members' comments and recommendations were compiled by subject matter, consistent with the subjects called for in the presentation agenda, to form Sections 2 through 5 of this report. Section 1 is a summary of the main conclusions and recommendations.

Section 1

SUMMARY OF MAIN COMMENTS AND RECOMMENDATIONS

The U.S. gas-cooled reactor program was initiated in the late 1950s with the development of design concepts based upon earlier work done primarily in the United Kingdom on lower temperature gas-cooled reactors. Two high temperature plants have been constructed and operated in the U.S.: the 40 MWe Peach Bottom plant, completed in 1967 and operated until 1974, and the 330 MWe Fort St. Vrain plant, completed in 1974 and scheduled for defueling/decommissioning in 1990.

The U.S. high temperature gas-cooled reactor program is primarily funded and managed by DOE with additional funding and management support provided by utilities through GCRA. Private funding has also been provided by GA. The program is currently focused on the development of the MHTGR, a four-module, 540 MWe plant, in which enhancement of passive safety characteristics is emphasized. A base technology program supported by DOE includes fuels performance and fission product behavior, graphite behavior, and metals behavior, with concentration on fuels and fission products development. EPRI is also funding a modest technology effort, concentrating primarily on the development of magnetic bearings for the main helium circulator. Other EPRI nuclear research programs have application to HTGR development.

The U.S. electric utilities have consistently endorsed and supported the development of the HTGR concept. The most important of the recent expressions of the utility support for HTGR development was included in the report of the Energy Research Advisory Board's Subpanel for Advanced Reactor Development (April 1986).

The MHTGR represents the most recent visualization of an HTGR that could be made available for utility deployment upon successful completion of a demonstration plant project. Overall, the utility industry evaluation team believes that the MHTGR should be considered a viable application of an advanced nuclear concept and deserves continuing development. This general conclusion should be remembered when reading the following specific comments. The comments and recommendations in this evaluation report are intended as constructive suggestions for improving the applicability of this very promising plant design to utility systems.

This section of the report extracts and summarizes the main conclusions and recommendations explained in more detail in the subsequent sections. The items included in this section are selected on the basis of their significance to the MHTGR and/or the expressed strength of the evaluation team's opinion on the subject. The subsequent sections include many additional comments and recommendations not highlighted here.

1. The MHTGR program has developed a plant design which offers several attractive characteristics, especially in the safety arena. The most significant of these characteristics is the non-reliance on plant protection systems for assuring public safety, thereby avoiding the cost of design, construction, opeation and testing of such systems and the burden of frequently reviewing their reliability and of sometimes upgrading them. The design promises to provide a passively safe response even to severe accidents in which the reactor shutdown system is assumed to fail.

   Nevertheless, one design feature which may have to be reviewed to assure regulatory and utility acceptance is the use of the TRISO particle as the primary barrier in the MHTGR containment system. This application of the TRISO fuel is unique to HTGRs. It is the MHTGR program's position that these coated fuel particles maintain integrity during all normal and licensing basis events and that fission product release from MHTGR fuel is therefore dominated by contamination and manufacturing defects. The MHTGR program has calculated that, assuming stringent fuel process specifications are met, the fission product release even under extremely low probability, severe accident events will still meet the dose limiting regulations, without a need for a secondary leak-tight containment structure. Plant operation and out-of-pile test results, although limited in scope so far, confirm the above performance claim. However, until the fuel demonstration program has progressed further, some uncertainty remains that these particles can be manufactured and inspected on a commercial basis to the quality required and that they will consistently meet integrity requirements under severe accident conditions. Providing confidence that the fuel meets all fabrication and operational expectations is the fundamental key to utility acceptance and success of the MHTGR concept. A comprehensive testing program, possibly including confirmatory result from a prototype plant, is the mechanism which will provide this confidence.

2. The predicted frequency and consequences of bounding events is so low in the MHTGR that no low-leakage containment is provided around the primary circuit boundary. Confirming the predicted frequencies and consequences will require proving not only the fuel quality and integrity as noted above, but also the accident analysis methods and the fission product transport methodology. Even then, it will be difficult to obtain public and regulatory acceptance of the non-traditional containment approach. A fall-back position, specifically one enhancing containment, should be developed so that the design and cost impact can be understood.

3. Two areas where technical needs and dependent costs may have

been significantly underestimated are in plant manning levels and in spent fuel storage and disposal. The number of operating crews and the number of total plant personnel are less than can be supported by extrapolation from US nuclear plant experience to-date. The spent fuel storage capacity does not allow for the real-life delays to governmental removal of the spent-fuel from the site, and the costs assumed for the storage facilty and for the storage casks seem inadequate.

4. The refueling plan for the MHTGR is to replace half the fuel every 20 months. The MHTGR program indicates 21 days has been allotted for the refueling outage. Virtually the entire core is removed from the reactor vessel to a fuel-handling bay where half of the fuel is replaced as the core is reloaded into the reactor vessel. The number of fuel handling operations is quite large (roughly 1000 fuel and reflector blocks must be handled in a typical refueling) and must be accomplished without misloading and fuel damage. The MHTGR program has spent considerable effort designing the equipment to achieve this high rate of handling by using highly automated equipment, providing limited built-in redundancy and spares, and has some experience base from Fort St. Vrain on which to extrapolate this performance.

   Reliability of the fuel handling equipment will be essential to maintaining the refueling schedule and plant availability, and the MHTGR program will need to provide additional assurance regarding adequacy of the fuel handling and refueling methods.

5. The MHTGR design offers several attractive characteristics in the safety arena which may justify a premium in the busbar costs. However, the MHTGR project must strive for a competitive busbar cost with nuclear and coal-fired alternatives. Based upon the presentations given to the

utility team, and recognizing the potential impact of issues discussed in this report, such as containment, staffing levels, spent fuel storage and disposal, it is unlikely that the visualized MHTGR will be economically competitive with contemporaneous light water reactor plants. Achieving an economically competitive design appears to be the greatest challenge facing the MHTGR project. Accordingly, the utility evaluation team recommends that the economic challenge facing the MHTGR be recognized and that more emphasis be given to potential cost reducing improvements.

6. Seismic capability has been a special concern for the prismatic cores, made up of large blocks of graphite. One feature of the MHTGR design which helps deal with the seismic concern is the relatively deep embedment of the plant, which may help alleviate the motions and loads caused by a seismic event. The MHTGR program should make the seismic design basis of the plant more fully explicit, i.e., how the various structures, particularly including the core, are designed to provide adequate margins for the seismic events postulated in the design basis.

POST-HEARING QUESTIONS AND ANSWERS

ANDREW C. KADAK
PRESIDENT AND CHIEF EXECUTIVE OFFICER
YANKEE ATOMIC ELECTRIC COMPANY

MARCH 5, 1991

QUESTIONS
SENATOR MALCOLM WALLOP (R-WY)
NUCLEAR PROVISIONS OF S.341, "THE ENERGY SECURITY ACT OF 1991," DATED MARCH 5, 1991.

QUESTIONS FOR ALL WITNESSES:

The Department of Energy estimates that a combination of increases in demand and retirement of existing electric generation capacity will require an additional 200,000 megawatts of capacity by the year 2010.

QUESTION 1a:

Would you agree with Mr. Wolfe's statement that until recently there has been considerable excess electrical capacity in this country, but that this era is coming to an end?

ANSWER:

Yes, I agree with Mr. Wolfe that the era of excess electrical capacity is over. DOE's estimate of approximately 200,000 megawatts of new capacity being required by the year 2010 is a realistic scenario that can be used for planning additional capacity.

In the late 1960's, electricity demand was increasing at about 7% per annum, which was effectively doubling supply requirements every ten years. Thus, utilities with their long planning horizons of 12 to 15 years, were adding large amounts of generation capacity. The oil shocks of the 1970's and increased conservation efforts cut demand increases by over half, leaving utilities with considerable excess capacity. Coupled with excess supply, the regulatory and legal difficulties of siting and building new capacity caused most utilities to throttle back the construction of new generating facilities. However, over time, the nation's economic growth has caused electricity demand to catch up with our excess supply. While it may not be desirable to have excess electricity supply, it is very undesirable to have electricity supply shortages.

There are significant regional indications that demonstrate the end of excess electricity supply. In 1988 there were a series of brown-outs in Massachusetts, that cost its high-tech industry at least $80 million. The warning signs continued in 1989, with rolling blackouts in Texas and Florida during the Christmas season and in 1990 with brownouts/blackouts in the mid-Atlantic states during the summer months. The warning signs are prevailing in 1991. As I mentioned in my testimony, the State of Florida is still experiencing rolling blackouts on cold days. I speak of this with some personal knowledge as while I was speaking to my mother on the telephone last February, her home in Florida, experienced a rotating blackout. This is an unacceptable way for Americans to live. Our nation cannot tolerate electricity shortages while trying to successfully compete with Japan, Korea, and Europe in the economic arena.

In the area of forecasting, which looks out about ten years in time, I would recommend the use of a probabilistic technique to assess varying scenarios. It has been observed that in times of slow economic growth, forecasts are necessarily low. In periods of high economic activity and high power growth, the forecasts naturally continue to assume the same, resulting in high growth forecasts. The time at which the forecast is made, greatly influences the resultant energy growth scenario. Thus, if we apply a more rigorous probabilistic approach, which I believe the Department of Energy has done, the temporal perceptions of energy demand versus supply would be levelized. It is important to do this because generation cannot be put on line on short notice. To assure reliable power supply, the waves of economic activity and perception must be levelized so that power will be available when required.

QUESTION 1b:

Faced with today's environmental laws, such as the Clean Air Act, in your judgement, can this requirement for new generation capacity be satisfied without a greater role for nuclear power than is possible under present circumstances?

ANSWER:

I do not believe very many dispute the fact that nuclear power is a major electric generating source available today that can meet the Clean Air Act standards. Unlike many fossil plants, the nation's existing nuclear power plants meet the provisions of the Clean Air Act of 1990, without the need for extensive backfitting. Even more importantly, nuclear power plants do not emit any CO_2, which is an atmospheric pollutant not covered by the Clean Air Act, but nevertheless of increasing concern because it is a primary cause the "greenhouse effect" or global warming. With that in mind, I see new nuclear power plant construction as a key component in a balanced mix of generation capacity and conservation efforts. Certainly, nuclear power can and should generate much more than 20 percent of this nation's electricity supply - the environment and our economy will be significant beneficiaries.

QUESTION 1c:

In your judgement, can the third world meet its anticipated requirements for electricity without a large expansion of nuclear power?

ANSWER:

The report of the World Commission on Environment and Development in 1987 stated that the "continued prosperity of the developed world depends on the rapid extension of prosperity to the less developed nations in an environmentally responsible manner." As we know from our own experience, electricity has become the energy source of choice in today's economic competition. Thus, for the Third World to prosper, its electricity supply must expand.

For electricity supply to expand in the third world, fossil fuels are the likely candidates, hopefully, with modern pollution control devices. This expansion of fossil fuel use will create global environmental problems which can be mitigated by industrialized nations increasing their use of nuclear energy to counter the increased fossil emissions. Eventually, the Third World may make nuclear power part of its electrification process, but for the foreseeable future it is best to encourage small and low capital projects and avoid the concerns regarding proliferation.

QUESTIONS 2a & 2b:

Would you agree that the long-term promise of nuclear energy is essentially unlimited through the development of advanced liquid metal reactor technologies?

In your judgement, should DOE's program be more aggressive in this regard?

ANSWER:

DOE's program in developing liquid metal, as well as gas cooled reactor technologies, needs to be reviewed to be sure that the technology development has progressed sufficiently to construct a prototype commercial plant. We have had many years of research and development on liquid metal reactors that provide a good basis for building a demonstration reactor. I am unfamiliar with the details of the DOE funding or long-term schedule for its construction, but from a utility's perspective, the breeder option and whether it is exercised or not will depend on the economics of the technology and the cost of uranium as part of the light water reactor fuel cycle. When those two come together, the utilities will be in a position to make the decision to order a commercial liquid metal reactor.

Before that point is reached however, it is my judgement that our focus legislatively, financially, and technically, should be aimed at developing the next generation of mid-sized and evolutionary plants of the light water variety to assure that there is a nuclear industry to be able to develop these future technologies. I cannot envision a situation where if we do not have new nuclear orders in the near-term, that in ten to perhaps fifteen years in the future we would not be interested in another nuclear technology since its base - both in technology as well as support and experience - will have been eroded.

Thus, if I were to answer the question as to the priorities of the Department of Energy, they would be to assist in the design certification of more passive designs and evolutionary light water reactors; assist in the licensing reform to restore investor confidence in the technology, and; then fund the research and development portions of the liquid metal and gas cooled reactor technologies.

We need to keep nuclear as an option and the only way to do that in the short term is with the next generation of light water reactors.

Institutional problems are often cited as the reason why we cannot build nuclear power plants in the United States. Japan and France are often used as examples of it taking only four to six years to build a nuclear power plant and put it into operation.

QUESTIONS 3a & 3b:

Why is this the case in Japan and France? If I am correct these countries rely on a licensing system similar to that in the United States. Would you comment?

Are standardized designs critical to expediting this process?

ANSWER:

It is my understanding that the regulatory systems in Japan and France are quite different from those in the United States. The regulations, in terms of safety, may not be significantly different but it is the application of those regulations and the system that we have created in the United States that is a key factor in the greater length of time and money it costs to build nuclear plants. Both Japan and France have the equivalent of the Nuclear Regulatory Commission and have established safety standards comparable to ours. But, neither country has an adjudicatory system that emphasizes conflict rather than conflict resolution.

I am much more experienced with the regulators in France. It is their position that when an issue develops, to resolve it with the utility to reach the best technical solution. France's regulatory criteria and solutions may be as stringent as those that might be applied in the United States, but they are able to resolve problems quicker. Resources are focused at resolving the problem rather than preparing for licensing proceedings. It is my recommendation that the committee, as they consider licensing reform, involve and seek testimony from the regulators in France and Japan to learn how they carry out their regulatory responsibility and contrast it to ours. It is clear that all nations strive for the safest operating plants they can and establish rules of conduct that would promote such practice.

I believe that standardized design would certainly help the United States expedite the licensing process. As you may be aware, in the 1970s, the United States used a process called replication of nuclear designs. It was another word for standardization but I think it more accurately represents the realities given different siting conditions. In replication, the Atomic Energy Commission approved a standard design and issued an associated safety evaluation report. When a utility filed an application to construct a nuclear power plant, the safety review was limited only to differences from the standard that had already been previously approved. Thus, the review was rather quick since few, if any, changes were made. The only area of review that required analysis was that associated with the environmental report.

A specific case was the proposed Charlestown Nuclear Plant in Rhode Island. The replication process was used and it was found to work effectively. This plant was patterned after several similar plants that were going to be built in New England. The review process was quicker and much more efficient without reducing any safety levels. Where the process bogged down, unfortunately, was in the interventions associated with the application. The necessarily adversarial versus negotiation system to resolve conflict created and continues to create unnecessary delays.

QUESTIONS 4a, 4b, & 4c:

Passive safety features are critical to the public's acceptance of nuclear power. Would you agree?

In your judgement, do liquid metal reactors and high temperature gas-cooled reactors have advantages with regard to passive safety features?

If we are concerned for the future of nuclear power, would you agree that there is a need for a more active federal support for these technologies in addition to "advanced" light water reactors?

ANSWER:

I would agree that public confidence in nuclear power is essential now and in the future. Public confidence is attained by good performance. If performance is good, the technical details of the design are immaterial. While passive safety features are important in the next generation of nuclear plants, to show that progress is being made in design, I do not believe they are going to be the critical issue as to whether or not new nuclear plants are ordered. It is unrealistic to assume that simply because some passive features have been incorporated into a new design, that no active safety-related components will be required. Rather than debate passive versus active, the responsibility to the public is to develop designs that are improved and to demonstrate why and how they are better. I do not think that the passive nature of new reactors should be over-sold because in the long run, nothing is ever totally passive.

At this stage of the design process, the passive safety features of the Advanced Liquid Metal Reactors (ALMRs) and High-Temperature Gas Reactors (HTGRs), while different, do not have an overall safety advantage when compared to Passive-Advanced Light Water Reactors (P-ALWRs). My opinion is based upon Yankee's ongoing participation with other utilities in the review of the designs and supporting analyses for these reactor concepts. Any distinct advantage of the passive safety system for a particular reactor concept is not likely to become evident for several more years when the designs are more complete.

It is important to remember that each advanced reactor concept must protect the public health and safety by restricting the actual and potential release of radionuclides within the same set of United States Nuclear Regulatory Commission (USNRC) requirements, primarily contained in the Code of Federal Regulations, and the Dose Protective Action Guidelines of the Environmental Protection Agency. Each reactor type must also address; the USNRC's Advanced Reactor, Safety Goal, Severe Accident, and Standardization Policy Statements in order to establish decision criteria against which the designs can be reviewed; and the USNRC regulatory guides and general design criteria, some of which are being reformulated to account for new design approaches. Finally, each reactor type must address utility requirements and recommendations in order to produce a viable plant design.

This design development process is actively underway for several advanced reactor types with much design work yet to be completed. Thus, it is premature to draw strong distinctions

between the advanced reactor types at this time because perceived advantages or disadvantages are subject to change as the designs progress.

As I said in the response to an earlier question, we should develop both technologies to a point where they can be demonstrated on a commercial scale and let the market place decide which is the more appropriate technology for use. We do not want to oversell either of these concepts because by doing so expectations are unnecessarily raised beyond those which might be achievable.

QUESTION 5:

Would you agree that the future of the nuclear power industry rests in the development of advanced nuclear reactor designs and streamlining the regulatory structure to bring on line new, safer generations of nuclear reactor technologies.

ANSWER:

I am convinced that the future of nuclear power is now. We cannot ignore the important steps that need to be taken with regard to light water reactors both in the technical as well as licensing arenas if a future for nuclear power exists. The first step towards the future is the license renewal of the nation's existing nuclear plants as I have earlier testified.

Federal support for advanced technologies such as liquid metal and gas cooled reactors is essential if it is to play a role in meeting our needs beyond the year 2010. The needs that I would identify is component design verification to assure that the performance of components in a demonstration reactor are as advertised. Much of this work has been done already in the development of the Clinch River Breeder Reactor as well as the Fort Saint Vrain gas cooled reactors. I think a great deal more could be learned through the development, if it should proceed, of the national production reactor (NPR).

I would support Mr. Buckman's idea that the NPR could become a prototype for our commercial gas cooled reactor technology. If utilities are to seriously consider liquid metal as well as gas cooled technologies they must have demonstrable evidence that they work. Utilities are no longer in the position to become the test beds for new reactor concepts. Thus, additional federal support would be required to assure the technology is ready for the marketplace in the next century.

QUESTION FOR UTILITY WITNESSES
SENATOR MALCOLM WALLOP (R-WY)
NUCLEAR PROVISIONS OF S. 341, "THE ENERGY SECURITY ACT OF 1991," DATED MARCH 5, 1991.

Much has been said about the need for this legislation if nuclear power is to play a role in our nation's energy future. Let us assume that the legislation before us is passed and accomplishes all that is intended regarding licensing reform and the NRC's certification of advanced reactor designs.

QUESTION Aa:

What are the plans of each of your utilities regarding new nuclear electric generation capacity?

ANSWER:

Passage of this legislation which is aimed at an improved licensing process and NRC's design certification, will go a long way towards renewing utility interest in the nuclear option. It is a necessary but unfortunately not sufficient condition for utilities to actually order the next nuclear plant. Clearly, without these basic steps, however, no utility would consider new nuclear generation.

The additional factors that need to be weighed are the role of states in federal licensing activities; in particular, the state public utility commissions as well as state's siting agencies. They have a significant role to play in determining whether another new nuclear plant is ordered. If state siting conditions become so onerous that even if we had an affective federal licensing process and on the shelf designs which NRC had preapproved, states could easily string out the construction and siting process thereby making it impossible to build a plant.

In addition, a new state public utility regulatory framework needs to be developed that does not penalize utilities for undertaking projects and then with 20/20 hindsight determining how much of the plant's costs would be included in rate base. I understand efforts are being made in that regard at the present time with the utility and the regulatory community. It is hoped that these steps will restore confidence of the utility community in the state regulatory process such that the nuclear option becomes viable once again.

Another important factor in determining whether a utility will consider nuclear is the outcome of the national energy strategy debate. I have long felt that leadership on such a vital issue is overdue. The Congress, as well as the Administration, needs to come forward and provide the necessary leadership on the importance of nuclear power as part of our national energy security. This bill, as well as the Administration's bill, go a long way toward providing this leadership for the American public. Public support for nuclear power can be achieved. This cannot be done by portraying it as an alternative of last resort but rather as a clean, safe and economic source of energy for the next generation of Americans. Congress, the Administration and the utilities have a role to play in developing that consensus.

As to Yankee's specific plans for ordering the next nuclear plant, I cannot say, because it is the prerogative of the ten retail utilities that own the company. However, if the objectives of this legislation, as well as other points including those raised above and identified in my responses to other questions can be met, I believe a New England utility would order another nuclear power plant.

QUESTION Ab:

What would be required for each of you to place an actual order?

ANSWER:

I've addressed some of the prerequisites above but they would also include comments made by Anthony Leness at a recent conference which are provided in Table 1. Mr. Leness is an investment advisor who follows nuclear issues closely for the investment community. The criteria he identifies should give you an idea of what the investment community is looking for in the next nuclear order.

It's my opinion that nuclear power has demonstrated itself to be reliable, economical and safe in the United States. There are some very bad examples of where regulators have treated utilities, correctly or incorrectly, quite harshly on their investment in nuclear plant construction. There are also examples of interminable delays in the siting and construction of these plants largely due to a process that is flawed. The licensing process that has been given much attention is that associated with the Nuclear Regulatory Commission. The entire federal and state regulatory role in terms of all the permits required prior to the operation of a nuclear power plant needs to be reviewed.

The country needs to take a broader view of nuclear plant regulation if we really want to make meaningful improvements to bring these plants on line in a time frame that has been done in Japan and France. This look is long overdue and I laud efforts of Congress at challenging the status quo.

TABLE 1

Requirements for the Next Nuclear Order*

1. The National Energy Strategy must call for the development and deployment of nuclear power plants. The utilities must support this strategy and must extend this support to the local level.
2. Progress must be made on the disposal of spent fuel whether it be in a repository or on-site storage. The investment community must be assured that this problem is under control and convinced that it is so.
3. The next generation of design must be perceived as safer and it must be thought through and complete before the design is sold to the public.
4. The investment community must be convinced that the regulations will not allow change during construction. They must also be assured that the designs are preapproved and will be built as designed.
5. The size of the new, advanced plant should be between 300 and 600 megawatts to minimize financial exposure.
6. Safety permits must be maintained at a federal level, no local or state licensing.
7. The construction process must be standardized.
8. The role of the Public Utility Commission should only be limited to timing, the site, and the cost.
9. The cost of the facility must be predictable, fixed price, and systems must be in place to contain costs.
10. Rolling prudence reviews should be part of the process, recover as you go.
11. All permitting must be done in advance.
12. The NRC must have as close to one-step licensing as practical.

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* Extracted from remarks of Mr. Anthony Leness, Managing Director, Merrill Lynch & Company (November 13, 1990).

QUESTIONS FOR ANDREW KADAK
FROM SENATOR JOHNSTON

THE PROCESS LAID OUT IN TITLE XII

In his testimony, Mr. Young identifies three main problems with the provisions of Title XII -- that DOE is already doing most of the things envisioned under Section 12005; that it is too early to expect a utility to order a nuclear plant, even with the benefits of Section 12005; and that direct federal government participation in a demonstration project would be inappropriate.

This is a fairly strong rejection of Title XII.

QUESTION 1a:

Do you believe that DOE can do everything necessary to revive the nuclear option without any endorsement or encouragement by Congress?

ANSWER:

I do not believe that the nuclear option can be revived without the specific endorsement by Congress and the President stating that nuclear power is important for this country. DOE has a role to play in the commercialization of reactor technology projects so that utilities will have the necessary degree of confidence for investing in a technology. This is true of the advanced design passive plants, as well as the liquid metal reactors and gas cooled reactors.

Approximately a year ago, I suggested a program to Secretary Watkins about how DOE might participate in a commercialization effort for the near-term advanced light water reactors. That proposal basically recommended that DOE fund a utility to identify and select a technology that they would be willing to build and thereby establish a prototype for the rest of the industry to use in its standardized product line. My recommendation was for DOE to provide the utility the resources and support necessary for demonstration of the technology. The encouragement of Congress is important to ensure that DOE continues to focus on design certification of advanced light water reactor technology and licensing reform in order to bring the evolutionary and passive designs into operation this decade, as well as provide for the later demonstration of the more advanced technologies.

QUESTION 1b:

What parts of Title XII, if any, do you think would be helpful in ensuring that advanced reactor designs will be available when needed?

ANSWER:

All parts of Title XII are helpful in ensuring that advanced reactor designs will be available when needed. In the area of advanced design light water reactors, DOE funding of design refinement leading to certification is necessary. In the more advanced technology plants, such as gas-cooled reactors, as well as liquid metal reactors, a more significant effort will be required before utilities will step forward and actually construct such a plant. Too many lessons of the past will have to be ignored to expect a utility to simply buy a design based on a concept. In my opinion, for advanced gas-cooled or liquid metal reactors to succeed, the DOE, in cooperation with the utilities, will have to build a prototype plant to demonstrate the feasibility and the operability of the technology before it becomes commercialized. The decision to solicit construction of a prototype plant, however, should await further technological development of the options, in order to ensure a selection process which leads to a successful future commercialization program.

QUESTION 1c:

What could be done to make Title XII more useful?

ANSWER:

The provisions of Title XII are already useful, in that they directly address several of the key uncertainties holding back construction and operation of new nuclear plants. To the extent that is possible, the committee may wish to consider addressing other issues which currently impact a utilities decision to proceed with nuclear plant construction. These include: waste disposal, state-local rate and siting issues; streamlining federal regulatory authority; etc. With respect to public hearings, it is important that Title XII ensure a regulatory process such that once a design is certified and a combined construction and operating license issued, the only action that the NRC must take will be to confirm that the plant has been built (and subsequently operated) as specified. Title XII should also ensure that no second hearing will be required unless substantial and credible evidence is provided that is contrary to NRC's confirmation and cannot be resolved without a hearing. Further, the plant should be allowed to operate pending a resolution of the issue since the presumption would be that NRC had already concluded that the plant was safe to operate.

UTILITY PARTICIPATION IN A DEMONSTRATION PROJECT

QUESTION 2:

Why wouldn't it be attractive to a utility to participate in a demonstration project that received 50% federal funds?

ANSWER:

In my opinion, I think it would be very advantageous and attractive for a utility to participate in a demonstration project provided that it was properly administered. In my response to Question 1a., I suggested that the utility be given the ultimate responsibility for design and construction of the demonstration project consistent with functional objectives. They then would assemble the appropriate design and architect engineer team to ensure that their needs are met. Their needs are defined as power production and reliable operation from the standpoint of operations and maintenance. This process would bring to market a proven design with utility input that is focused and timely.

Speaking on behalf of Yankee Atomic, the Department of Energy as well as the Electric Power Research Institute have helped us to fund our license renewal program. They have been very instrumental in the success of the lead plant project and we believe a similar arrangement can also work with a new reactor demonstration project. It saves money and provides for a rapid transfer of technology.

QUESTION 3:

Similarly, why wouldn't it be attractive to a utility to participate in a project under Section 12005, the so-called institutional demonstration?

ANSWER:

Section 12005 provides for DOE to encourage the siting, financing, licensing, construction, and operation of nuclear generating facilities. In selecting a proposal, the DOE is to consider if the proposed technology is appropriate (i.e., utilizes modular construction techniques, exhibits passive safety features, etc.); if it uses a standardized design; if the facility can be successfully financed, constructed, and licensed; if the federal government receives an equitable return; and the extent to which the successful construction and operation of the facility will improve the availability of nuclear reactor technologies for generating commercial electric power.

Accordingly, Section 12005 addresses several of the key uncertainties associated with construction of a new nuclear plant: financial confidence and support; regulatory/licensing stability; and technological feasibility. Reasons why a utility would not participate in an institutional demonstration under Section 12005 would essentially be these associated with other power plant construction issues (state DPU rate issues, state-local siting processes, etc.) and nuclear power issues (public confidence, waste disposal, uranium enrichment costs, and O&M cost containment including future regulatory ratcheting, etc.).

No one bill can fully address and resolve all the issues potentially impacting a nuclear power plant construction decision, even as comprehensive a piece of legislation as S.341. The legislation, however, does go a long way in the right direction to provide for utility participation.

QUESTION 4:

Last year, DOE offered to assist a utility to obtain a license as part of a demonstration project, but got no volunteers. Why was there so little interest among the utilities in this program?

ANSWER:

In my opinion, DOE's historical approach to nuclear research and development has been too prolonged and targeted to technological development rather than utility acceptance. Although DOE has previously solicited utility input in proposals for the development of advanced reactor technologies, that input has been linked to that of consultant, not developer. I would contend that if the product of a demonstration is to be used by utilities, then the utility should be in control of the demonstration and not the vendor. A successful demonstration project must allow the utility to seek out competitive proposals for a technology that best suits its generation and maintenance needs. The level of interest expressed in a particular technology would then drive the decision as to which technologies should be funded. If no utility is interested in developing, with DOE funding, for example a metal cooled reactor, that strong message says that even if one is developed - no one will buy it. If the utility manages the design and construction of a demonstration project, and if the project is a success, other utilities will buy it.

For the above reason, I have previously recommended that the DOE research and development program award several contracts to utilities to design and build demonstration plants of different technologies - gas, advanced light water, and liquid metal. Each utility would then seek out competitive proposals for design and construction to suit their generation and maintenance needs. DOE would then quickly see the level of interest in competing technologies by the interest expressed in the various alternatives.

FUTURE ORDERS OF NUCLEAR PLANTS

QUESTION 5:

How much of the estimated 150 to 250 gigawatts of new electrical capacity needed over the next two decades do you expect will be supplied by nuclear power?

ANSWER:

This is a difficult question to answer because it depends on the success of this legislation as well as other factors such as environmental concerns, economic growth and public perception. Thus, any response to this question is of a speculative nature.

I believe that there will, over the next three to five years, be orders for two to three new nuclear plants to be built under a joint venture, demonstration concept. These will be the first orders for a nuclear power plant since 1978 and will therefore be closely monitored by the utility industry. If these first orders make it through the licensing process in an orderly and predictable manner and the factors mentioned above fall within expected regimes, then there could be a substantial number of new orders occurring around the year 2000.

Most likely, utilities would begin the wave of new ordering with an equal mix of new, more passive 1300 megawatt and 600 megawatt plants. In the early 1970's, utilities were ordering an average of 30 nuclear plants per year, and there is no reason why half as many could not be realized in the early 2000's. So, given a six-year construction and start-up lead time, it is not unreasonable to expect that by 2010 about 60 gigawatts of new nuclear capacity could be installed and in commercial operation. Thus, about 25 to 40 percent of DOE's forecast of 150 to 250 gigawatts of needed capacity could, and should, be nuclear.

It is important to recognize, however, that to achieve these estimates -- which are reasonable and practical -- that decisions must be made and actions undertaken over the next several years.

QUESTION 6:

What portion of these orders do you expect to be:

1,300 megawatt so-called "evolutionary" LWRs?
600 megawatt so-called "advanced passive" LWRs?
Modular high temperature gas reactors?
Liquid metal reactors?

ANSWER:

I think the answer to this question is extremely hard to forecast but let me give you my perspective as it relates to why a utility would pick a particular design option.

First, 1300 megawatt evolutionary light water reactors. Depending upon the utility size, I think this is a very attractive option since this same design is going to be built in Japan. This design takes advantage of thirty years of light water engineering and operating experience. The only drawback to the design is that it is probably larger than most utilities can absorb into their grid. This leaves the potential of joint ownership where utilities take portions of the power and ownership thus minimizing the cost and the capacity requirements. This is the way the original Yankee plant was built and it provides utilities the necessary risk and power sharing. Clearly, this type of plant would have to be on a grid sufficient to be able to withstand its shutdown. There are a number of utilities that could very well be interested in a 1300 megawatt design since they do have economies of scale associated with them.

The 600 megawatt advanced passive designs are breaking into slightly different technologies although their size is more attractive to most utilities. The newness of different features of the technology would create some hurdles, albeit low, to ordering that particular plant. In addition, first of a kind startup problems as well as design details need to be worked out, but in my judgement they are the more likely product to succeed over the short term since they offer the smaller size, quicker construction time and smaller dollar at risk.

As to the modular high temperature gas reactors, I don't see an order at least until a demonstration project has operated successfully. My best estimate is that we wouldn't see an order until the year 2007 to 2010. I put the liquid metal reactors in that same basic category even though the French have already demonstrated the technology.

My opinion is that we might import French technology if liquid metal reactors are to be introduced on a faster time scale. I am impressed with the EBR-2 record and the 30 plus years of experience that they've had with EBR-2. However, for a utility to accept a radically new technology such as handling of liquid metal at high temperatures, a significant philosophical hurdle must be overcome. In addition, the economics of a breeder require reprocessing and I feel that this country is not going to re-embark upon reprocessing until and unless the price of uranium increases dramatically. At the present time, forecasts do not support such an increase.

I would like to add another nuclear option which is not considered in the question. This option is building a sister plant to an operating nuclear power plant on an existing site. I believe that if the utility has good experience with a technology, that is judged by the Nuclear Regulatory Commission to be safe and in conformance with applicable regulatory criteria that such a design has the best potential for the earliest development. Community acceptance would be there, especially if the plant performed well and the operating staff had a good record. The incremental risk and perception of another good performing plant at the same site would not be materially different. We would have, with just this one action, achieved a level of standardization which we are promoting in the next fleet of nuclear power plants.

QUALITY AND FOCUS OF DOE'S RESEARCH AND DEVELOPMENT PROGRAMS

QUESTION 7:

Do you believe that DOE's Research and Development Programs have improved over the last couple of years?

ANSWER:

I'm not in a position to judge DOE's R&D programs and whether they have improved over the last couple of years. I can only speak to DOE's support of our license renewal effort which as been very positive and has been singularly helpful in Yankee continuing its license renewal efforts. It is that kind of DOE involvement that I believe is helpful to jump start the nuclear option by bringing the funds directly to the utility to work on problems that they are currently facing.

QUESTION 8:

Are these programs better focused now than in past years?

ANSWER:

I am encouraged by DOE's recent activities which are supportive of NPOC's strategic plan to bring about the revitalization of the nuclear option. DOE has demonstrated a focus on design certification efforts which also deserve Congressional support. DOE's current activities are appropriately focused on the feasibility of technologies that will be capable of early development by the industry, as well as those technologies that will be ready for a commercialization project. I believe DOE has an important role in providing both the regulatory and financial support that will be necessary in the active construction of the next plant and that its recent efforts in this regard are fully appropriate.

TECHNOLOGY DEVELOPMENT

Your testimony is generally supportive of the process laid out in title XII. You emphasize, however, that the market must be useful.

QUESTION 9a:

When do you believe the market will be ready:

ANSWER:

Passage of S.341 will help ensure a ready market for new nuclear power plant orders in this decade. Key uncertainties in the area of funding, licensing, and technology are directly confronted. However, as I have stated in my responses to other questions, the financial community and utility confidence necessary to proceed with a new nuclear plant order will be based on a number of factors, including several beyond the scope of this legislation (i.e., waste disposal; public compliance/acceptance; state-local rate and siting issues). Some of these issues are not exclusively associated with nuclear power; however, given situations where construction of additional baseload is necessary, passage of S.341 will greatly improve nuclear power's chances of being the alternative of choice by the end of this decade.

QUESTIONS 9b and 9c:

Will the market be ready to select a technology on the time schedule envisioned in S.341? If not, how should this time schedule be reconciled with what is envisioned in S.344?

ANSWER:

I believe the future energy security of the nation depends upon passage of legislation with the scheduled goals of S.341. Resolution of the key nuclear power technology uncertainties addressed in S.341, will provide for a market ready to select a technology on the time schedule envisioned. As I previously stated, I believe that passage of S.341 will provide for the order of two-to-three advanced light water reactor plants under a joint venture, demonstration type concept in the next three to five years.

LICENSE RENEWAL

In your testimony, you talk at length about the need for license renewal. Certainly, this would be quite valuable for maintaining our current supply of electricity from nuclear.

QUESTION 10a:

Do you believe that legislation is necessary to make this happen?

ANSWER:

I do not believe legislation is required to make it happen. What I do believe is essential, however, is the recognition of its importance in any legislation that is proposed regarding national energy security. As the Atomic Energy Act provides the basis for our focus on nuclear energy, the National Energy Security Act should provide the basis for our future license renewal activities. If the committee were to incorporate in its record of hearing or committee deliberation that the renewal of licenses of existing nuclear power plants is an important strategic element of our future energy security, that would be very helpful in terms of the future public dialogue on the subject. It stakes a position of leadership necessary for the success of license renewal.

Although license renewal is not specifically a part of the legislative agenda for S.341 I felt that it was important for the committee to be aware of this facet of our national energy security. I appreciate your interest in this subject.

QUESTION 10b:

Does the NRC need additional legislative authority to renew existing operating licenses?

ANSWER:

The NRC has the legislative authority from the Atomic Energy Act of 1954 to renew the licenses of existing nuclear power plants. As you are aware, NRC is now in the process of promulgating the rules that would govern the renewal of licenses. In my opinion, the National Energy Security Act would be more complete if it made reference to the importance of our existing nuclear plants as part of that national energy security through the license renewal process. How that is best done, I would leave to your deliberations.

QUESTION:

Does the NRC need to be encouraged to pursue this issue aggressively?

ANSWER:

Nuclear Regulatory Commission Chairman Carr has stated that license renewal is his number one priority and he has followed through on his position. The Nuclear Regulatory Commission staff will be issuing a final rule in June 1991. What we need to be assured of is that this rule and its promulgating regulatory guidance and standard review plans do not make this process so unworkable that utilities, for the same reasons that they do not build new nuclear plants, will choose not to renew the licenses of existing ones. Although progress is being made in this area, we do have some concerns that the policy guidance of the commissioners will not be implemented by the staff.

QUESTION 10d:

In your opinion, is the NRC rulemaking process satisfactory?

ANSWER:

The NRC has not yet issued its final license renewal rule, but is expected to do so this summer. Yankee previously commented extensively on both the draft rule and the staff's draft regulatory guidelines for implementation of the rule. I remain concerned that the NRC, after a tremendous amount of industry involvement, will issue a final rule that fails to acknowledge that the issuance of a renewal license involves a far more limited scope than that associated with the issuance of a new license.

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Frederick W. Buckman
President and
Chief Operating Officer

March 22, 1991

The Honorable J. Bennett Johnston, Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510-6150

Dear Mr. Chairman:

Thank you for allowing me to testify before your Committee on S. 341 on March 5, 1991. The country will benefit greatly from your leadership on national energy policy.

In your letter to me of March 8, 1991, you and other members of the Committee asked several follow-up questions to which I am happy to respond.

QUESTIONS FROM SENATOR JOHNSTON

THE PROCESS LAID OUT IN TITLE XII

1. *In his testimony, Mr. Young identifies three main problems with the provisions of title XII -- that DOE is already doing most of the things envisioned under section 12005; that it is too early expect a utility to order a nuclear plant, even with the benefits of section 12005; and that direct federal government participation in a demonstration project would be inappropriate.*

   This a fairly strong rejection of title XII.

   a. *Do you believe that DOE can do everything necessary to revive the nuclear option without any endorsement or encouragement by Congress?*

      No. Revival of the nuclear option requires strong public endorsement as expressed by the Congress of the United States. We must remember that the Department of Energy (DOE) is viewed as an advocate and is focused on research and development rather than commercialization.

   b. *What parts of title XII, if any, do you think would be helpful in ensuring that advanced reactor designs will be available when needed?*

   Section 12005 is needed for the short term and section 12006 is needed for the long term.

c. What could be done to make title XII more useful?

As I said in my testimony, the next (advanced) reactor will most likely be an independent power producer (IPP) with several partners. Consequently, we need reform of the Public Utility Holding Company Act (PUHCA) as envisioned in Title X of S. 341.

UTILITY PARTICIPATION IN A DEMONSTRATION PROJECT

2. Why wouldn't it be attractive to a utility to participate in a demonstration project that received 50% federal funds?

Even with 50% government participation (a critical factor) there still exists a perception of high risk. To reduce this risk, even for the 50% private participation, there needs to be multiple owners, technology development and a licensing process that improves the likelihood that investors will receive an appropriate return on their investment.

3. Similarly, why wouldn't it be attractive to a utility to participate in a project under section 12005, the so-called institutional demonstration?

It is attractive but there is still a perception of high risk which must be addressed. Utilities are not likely to participate in a project where the use of licensing approval is high, the duration of engineering, construction and licensing is long, or the ability to finance is in question.

4. Last year, DOE offered to assist a utility to obtain a license as part of a demonstration project, but got no volunteers. Why was there so little interest among the utilities in this program?

There is still a perception of very high risk because of public acceptance, the waste problem and regulatory uncertainty. Regardless of their desire to pursue the nuclear option, utilities are still driven by financability and return on investment.

FUTURE ORDERS OF NUCLEAR PLANTS

5. How much of the estimated 150 to 250 gigawatts of new electrical capacity needed over the next two decades do you expect will be supplied by nuclear power?

Probably no more than 20% with nothing, or very little, on line before the millennium.

6. What portion of these orders do you expect to be --

1,300 megawatt so-called "evolutionary" LWRs?

600 megawatt so-called "advanced passive" LWRs?

modular high temperature gas reactors?

liquid metal reactors?

The 1,300 megawatt "evolutionary" LWRs and the 600 megawatt "advanced passive" LWRs share the risk of not being perceived as passively safe. Thus, I do not see more than one or two of the "evolutionary" plants with the "advanced passive" supplying the bulk of new orders before 2000.

The modular high temperature gas-cooled reactors (MHTGR) are the most promising and should be the bulk of the nuclear supply after 2000. Further, utilities will be slow to accept liquid metal technology and I do not see any being built.

QUALITY AND FOCUS OF DOE'S R&D PROGRAMS

7. *Do you believe that DOE's R&D programs have improved over the last couple of years?*

(see below)

8. *Are these programs better focused now than in past years?*

I am simply not close enough to these programs to offer an opinion.

ADVANCED REACTOR TECHNOLOGY DECISIONS

9. *In your testimony, you are very positive about the potential of the modular high temperature gas reactor for the next generation of technology. You indicate your belief that an HTGR would be a good candidate for a demonstration project under title XII. Other witnesses have testified, however, that the HTGR technology will not be sufficiently developed to meet the timeschedule for a demonstration project envisioned by title XII.*

Do you agree or disagree with that.

I believe that the MHTGR is the best candidate for the Section 12006 demonstration project. Much of the technology is already proven. Continued support of MHTGR programs will help and selection of the MHTGR concept for the NPR would guarantee adequate and timely technology development.

10. *You state in your testimony that the federal government should be careful not to force an elimination of options through competition for limited funding. You identify the clean coal program as a model for commercializing multiple options.*

Could you elaborate on this?

Key attributes of the Clean Coal Program that would be desirable for an Advanced Reactor Program are:

1. Well defined technical and programmatic criteria for project deployment.
2. Project cost-sharing arrangements that limit the Government share to 50 percent.
3. Project management control by the private sectoralong with related cost overrun responsibility.
4. Multi-year Congressional Appropriations administered on a project basis through DOE.

QUESTIONS FOR ALL WITNESSES

1. *The Department of energy estimates that a combination of increases in demand and retirement of existing electric generation capacity will require an additional 200,000 megawatts of capacity by the year 2010.*

   a. *Would you agree with Mr. Wolfe's statement that until recently there has been considerable excess electrical capacity in this country but this era is coming to an end?*

   Generally, nationwide capacities have been adequate. However, regional shortages exist and are becoming more widespread. Analysis of North American Electric Reliability Council (NERC) data will confirm this.

   a. *Faced with today's environmental laws such as the Clean Air Act, in your judgment, can this requirement for new generation capacity be satisfied without a greater role for nuclear power than is possible under present circumstances?*

   The Clean Air Act does not necessarily spell the end to expansion of fossil fuel plants. However, global warming, fuel diversity and national security considerations make nuclear power a compelling option.

   b. *In your judgment, can the third world meet its anticipated requirements for electricity without a large expansion of nuclear power?*

   Yes they can but I think it is in the world community's interest to encourage them to use nuclear power so that the planet is not harmed. The third world, by necessity, will do what it has to do to compete even if that means environmental pillage. We must therefore ensure that they have a economically and environmentally sound nuclear option.

2. a. *Would you agree that the long-term promise of nuclear energy is essentially unlimited through the development of advanced liquid metal reactor technologies?*

   (see below)

   b. *In your judgment should DOE's program be more aggressive in this regard?*

   All of the technologies offer extremely attractive long term promise. The ALMR must be evaluated and funded recognizing both its promise and its liabilities. I do not think more aggressive funding is warranted.

3. *Institution problems are often cited as the reason why we cannot build nuclear power plants in the United States. Japan and France are often*

used as examples of it taking only four to six years to build a nuclear power plant and put it into operation.

a. Why is this the case in Japan and France? If I am correct these countries rely on a licensing system similar to that in the United States. Would you comment?

In Japan and France, regulators work with the utilities because of their economic and policy interest in nuclear power. In the United States, licensing is combative and the NRC's role is largely one of an adversary to the utility.

b. Are standardized designs critical to expediting this process?

Yes, but the institutional problems mentioned above will remain.

4. Public confidence in the nuclear power option is essential if it is to play a role in our nation's energy future.

a. Passive safety features are critical to the public's acceptance of nuclear power. Would you agree?

Yes and this is the most important issue. You may recall from my verbal response to a similar question at the hearing was, "The answer to the question 'What if...?' has to be 'so what?'" From a public acceptance standpoint, we cannot have a plant whose meltdown probability is small. We need one whose design and physical characteristics simply preclude meltdown.

b. In your judgment, do liquid metal reactors and high-temperature gas-cooled reactors have advantages with regard to passive safety features?

Yes.

c. If we are concerned for the future of nuclear power, would you agree that there is a need for a more active Federal support for these technologies in addition to "advanced" light water reactors?

Yes. We need support for technology which is inherently safe and identifiably different from that which a large segment of the American people has already rejected.

5. Would you agree that the future of the nuclear power industry rests in the development of advanced nuclear reactor designs and streamling the regulatory structure to bring on line new, safer generations of nuclear reactor technologies.

Yes, but it also lies in (a) solving the waste issue, (b) continuing to operate existing nuclear plants safely and

(c) reducing regulatory risk by making regulatory interface less combative and more constructive as it is in the counties previously cited.

A. Much has been said about the need for this legislation if nuclear power is to play a role in our nation's energy future. Let us assume that the legislation before us in passed and accomplishes all that is intended regarding licensing reform and the NRC's certification of advanced reactor designs.

a. What are the plans of each of your utilities regarding new nuclear electric generation capacity?

None in the near term (before 2000). Our relatively limited capacity needs of about 500 megawatts will be met by purchase from nonutility generation.

b. What would be required for each of you to place an actual order?

1. Public acceptance and confidence
2. Reasonable economics for our customers
3. State regulatory support
4. Federal regulatory support
5. Partners
6. Financial community support
7. Reasonable rate of return
8. Waste disposal site

Yours very truly,

Frederick W. Buckman
President and
Chief Operating Officer

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March 21, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

I appreciated the opportunity to present my views on nuclear licensing reform at the Committee's March 5 hearing on Titles XII and XIII of S.341, the National Energy Security Act of 1991. The quality of the hearing matched the importance of the subject.

Your letter of March 18 enclosed follow-up questions from Senator Wallop for inclusion in the printed hearing record. The Attachment to this letter contains my answers to those questions. If any further elaboration would be helpful, your staff should feel free to contact me (202-639-7070).

Your licensing reform initiative is welcomed by those who see nuclear power as a substantial contributor to the nation's energy future. If I can assist in furthering this legislative effort please let me know.

Sincerely,

Marcus A. Rowden
Marcus A. Rowden

MAR:fa
Enclosure

cc: Senator Malcolm Wallop

ATTACHMENT

Question

> "In your opinion, if a portion of NRC's new Part 52 regulations had not been overturned in court, would Part 52 have provided the requisite assurance to the investment community for a new plant order"?

ANSWER

Part 52, while a welcome and constructive administrative reform initiative, does not, in my view, provide the requisite assurance for those who would be expected to shoulder financial risk in future nuclear power plant projects. As a contexting comment for my view, I would include within the term "investment community" both prospective utility license applicants and third parties in the financial or industrial communities who might be called upon to support project financing.

The position of the utility industry is most authoritatively expressed in communications to the NRC by industry leaders preceding adoption by the agency of a proposed Part 52 which included the opportunity for a preoperational hearing. Speaking for the Nuclear Power Oversight Committee (NPOC), James J. O'Connor, the Chairman and Chief Executive Officer of the Commonwealth Edison Company, stated as follows in regard to the potential for a hearing following completion of facility construction:

> "It is our firm belief that utilities will not order additional plants unless all issues are resolved before construction begins. ... Once the combined license is issued, we believe the plant should be handled no differently than a plant with an operating license -- the NRC has the responsibility to see that the plant conforms to

> all the conditions of that license. ... Without a process which would preclude opportunity for hearing after issuance of a combined license, the usefulness of the rule would be seriously impaired." (NPOC letter to NRC Chairman Kenneth Carr dated March 17, 1989.)

Reflecting a like position, the comments on proposed Part 52 submitted by the Nuclear Management and Resources Council (NUMARC), the organization responsible for nuclear power industry interface with the NRC on generic regulatory issues, took critical note of:

> "[t]he declared intention of the Commission in the proposed rule to provide the opportunity for a second hearing after a facility for which a combined license was issued has been constructed. We wish to make it clear ... that we believe a hearing at that point is not warranted ... [and] we would urge elimination of this second hearing, by legislation if necessary." (Letter to NRC from Byron Lee, Jr., President of NUMARC, dated November 7, 1988.)

Widespread industry and financial community concern as respects the preoperational hearing is reflected in two survey/studies, conducted under the auspices of the U.S. Department of Energy, analyzing NRC's Part 52 licensing reforms from the standpoint of utilities and the financial markets, respectively. As here pertinent, the utility industry survey concluded:

> "One major licensing issue that serves as a barrier to nuclear plants is the possibility of a post-construction public hearing. Seventy percent of the [utility] respondents said they would not order a plant, or it is unlikely that a plant would be ordered, if the possibility of such a hearing exists, even if the scope of issues which could be raised is very limited. Two responses are indicative of the feelings of the majority. One

> Western utility stated: 'This is a major barrier. While the concept of a limited scope is valid, the NRC and the federal courts have not shown the discipline to enforce a limited scope but tend to rule in favor of the intervenors.' Another said, 'Even a hearing with only one issue in question is a major barrier.'" ("Analysis of Nuclear Licensing Reform Proposals from the Perspective of Utility Chief Executive Officers", prepared for U.S. DOE by the Southern States Energy Board, March 1989, p. 2.)

The analysis of Part 52 reforms from the perspective of the financial markets contains the following pertinent assessment:

> "Investors must be assured that a permit to construct a nuclear power plant is also a license to operate it. Obtaining such a combined ... license (CP/OL) may require some additional up-front expense to prepare a complete design with performance standards, including specification of the tests and criteria which the completed plant must meet to commence operation. But that expense is less onerous than is the possibility that regulators will impose unforeseen delays in the form of additional requirements or reopen public hearings. Any procedural change which moves licensing and operating decisions to the beginning of the process, and assures investors that those decisions are final, is a welcome and necessary change. Conversely, any significant possibility, or uncertainty about, future hearings, new construction or operating requirements, or any other change in the CP/OL, will discourage investors from undertaking the project." ("Nuclear Licensing Reform and the Financial Markets", prepared by Touche Ross & Co., et al., for U.S. DOE, May 1989, p. 15.)

Thus, as further indicated in my responses below, remedial legislation dealing with preoperational proceedings is clearly necessary irrespective of the outcome of the pending Part 52 litigation.

Question

"What changes are required to Part 52 to instill investor confidence?"

ANSWER

As stated in my March 5 testimony, I question the wisdom of requiring a licensing hearing after a facility has been constructed. I believe that construction conformance -- the only matter not resolved by prior regulatory approvals under Part 52 -- can best be dealt with by the NRC's inspection and compliance process. That belief is grounded on the fact that, under Part 52, there will have been definitive resolution -- after comprehensive public hearings -- of all design and site safety issues in the site permit, design certification and/or combined license proceedings and the further fact that the combined license will contain the inspections, tests, analyses and acceptance criteria that will measure conformance of the constructed facility with the requirements of that license.

At a minimum, any hearing held at the preoperational stage should be limited to substantiated contentions of non-conformance with the acceptance criteria in the combined license. Moreover, any such hearing should not be permitted to delay facility operation absent a Commission determination that there is a sound safety reason therefor. I also believe that providing express legislative authorization for conducting such preoperational hearings with informal procedures -- rather than the trial-type procedures the Commission has historically used in reactor licensing -- would better serve the aim of timely issue resolution and reduce the delay risk posed by preoperational hearings.

The sum total of these reforms would be to limit preoperational hearing issues to those matters which could not have been considered in antecedent site permit, design certification or combined license proceedings, to expedite the process of issue resolution in any preoperational hearing that is held, and to remove the preoperational hearing from the "critical path" of facility operation where the Commission determines there is no threat to public health and safety. In my opinion, and consistent with the industry views quoted earlier, these measures would substantially enhance utility and financial market confidence in the nuclear power plant licensing process.

Question

> "Other than the preoperational hearing and the critical path issue, which of the changes you suggest would require legislation?"

ANSWER

In my judgment, the only change requiring legislation is that which would authorize the Commission to permit facility operation notwithstanding the pendency of a requested hearing. As respects the other recommended changes, I believe that legislation is highly desirable. While the Commission, in my view, has authority under current law to confine preoperational hearings to matters of license conformance, this issue is presently being litigated in the U.S. Court of Appeals for the District of Columbia Circuit; legislation would definitively resolve the matter. As respects Commission authority to utilize informal procedures for the preoperational hearing, I believe the Commission already possesses this authority. The Commission, however, has not been disposed to exercise that authority for reactor licensing because of what it believes to be an unclear legislative mandate, coupled with an historical practice of reactor licensing proceedings utilizing trial-type procedures. I would observe, in this connection, that the Court of Appeals for the District of Columbia Circuit has recently noted that the Commission's authority to use other than trial-type procedures for reactor licensing is still an "open" question as far as that court is concerned (UCS v. NRC, No. 89-1617, U.S. Court of Appeals for the District of Columbia Circuit, November 30, 1990, slip op. p.6). Given this background, and the desirability of Commission flexibility to tailor hearing procedures to the issues before it for resolution, legislative confirmation of the Commission's authority to employ informal procedures would be highly desirable.

Additional Request

> "One of the other witnesses, Mr. Glitzenstein, has stated that the provision on licensing in S. 341 precludes public input into the licensing process. Please state with

specificity your view as to the public participation aspects of the legislation."

RESPONSE

In my view, the licensing process of which Title XIII would become a part (i.e., a process which adds the Title XIII preoperational hearing provisions to the Part 52 processes for early site approvals, design certifications and combined licenses) substantially enhances meaningful public participation in nuclear power plant licensing.

In contrast to the flawed means for public participation inherent in the old "design-as-you-go" licensing process, Part 52 provides four distinct stages at which the public is afforded timely opportunity to participate meaningfully.

- First, hearing rights are provided regarding an application for an early site permit. Part 52 treats an early site permit as a partial construction permit and therefore requires a public hearing.
- Second, the public has a right in a design certification rulemaking to participate both in the notice and comment procedures and in the informal hearing before a Commission licensing board. Additional procedures, including formal hearings, also may be utilized in the rulemaking.
- Third, at the combined license stage, Part 52 provides for a hearing before construction begins -- one governed by the same procedures used in current

licensing proceedings for construction permits and operating licenses.

- Fourth, Part 52 provides an opportunity for hearing prior to commencement of plant operation where there is a substantiated allegation that one or more of the acceptance criteria contained in the combined license have not been met and that, as a result, there is good cause to prohibit or modify operation.

Title XIII of S. 341 does not alter these rights of public participation; indeed, it would confirm the Commission's authority to provide the preoperational hearing opportunity described above. What Title III would do, and what Part 52 seeks to do, is to limit the opportunity for a hearing as a matter of right to those issues that have not previously been resolved in the licensing process.

Neither S. 341 nor Part 52 preclude an interested party from seeking and the Commission from convening a hearing to consider significant new information where the Commission deems this appropriate in light of its regulatory responsibilities. In my testimony, I took note of the array of procedures provided by the Commission's regulations for the consideration of significant new information after a combined license has been issued. First, and foremost, Part 52 provides an expedited process for modifying the terms of a combined license in response to petitions that could be filed under 10 CFR §2.206, which could be based on new information or developments. Part 52 obligates the Commissioners themselves, rather than the NRC staff, to consider such petitions and to determine whether any immediate action is required before commencement of facility operation. In addition, new information relating to design safety can be raised by a rulemaking petition. And, finally, an interested party can seek a waiver from the Commission, on the basis of new information, to avoid the preclusive effect on issues resolved in a design certification rule. In each case, a Commission determination adverse to the petitioner would be subject to judicial review.

It is important to emphasize -- as Senator Johnston did during the course of the March 5 hearing -- that Title XIII in no way impinges on these Commission mechanisms for considering significant new information and on any hearings that might result therefrom. In short, Title XIII leaves intact the current NRC authority to take action to modify a combined license when this is necessitated by events subsequent to combined license issuance.

The central premise of Part 52 -- and of Title XIII -- is that definitive NRC decisions on design and site issues should be made on the basis of essentially complete industry submissions, and with full public input, before nuclear power plant construction begins. The new licensing process is, thus, a vast improvement on the process for public participation that has hitherto applied for nuclear power plant licensing.

According finality to licensing issues resolved in earlier proceedings and limiting preoperational hearings to matters that could not have been previously considered is fair, fully justified and an essential underpinning for a viable standardization program. Title XIII thus reflects both practical sense and good public policy.

Appendix II—Additional Material Submitted for the Record

STATEMENT OF

UNITED STATES NUCLEAR REGULATORY COMMISSION

TO THE

UNITED STATES SENATE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

CONCERNING

S.341, THE NATIONAL ENERGY SECURITY ACT OF 1991

SUBMITTED MARCH 22, 1991

The Nuclear Regulatory Commission (Commission) appreciates the opportunity to testify on Titles XII and XIII of S. 341, the National Energy Security Act of 1991, provisions of which address nuclear energy issues. The Commission fully supports the goals of Titles XII and XIII to encourage the development of advanced reactor technology and certified designs. The concepts reflected in the legislation would encourage the development and commercialization of advanced reactors that would be safer, less costly, and easier to build and operate than the current generation of plants.

Title XII sets forth a comprehensive framework for partnership between the Department of Energy and the private sector to provide for the institution and commercial demonstration of advanced nuclear reactor technology, and provides a process for the Commission to license that technology. Section 12003 provides for the submission to the Commission for certification of completed standardized designs for commercial nuclear reactors. Section 12004 requires the Department of Energy to hold meetings to obtain the public's views on advanced nuclear reactors and to take these views into account in submitting a plan to Congress which would carry out the purposes of Title XII. Section 12005 authorizes DOE to solicit and select proposals for collaboration with private sector parties who agree to become applicants for licenses for advanced reactors. This section provides for Commission input both at the time of solicitation and after proposals are reviewed. The section also provides for Commission licensing of prototype reactors in accordance with provisions that are similar to those of the Commission's Part 52. Section 12006 provides for the commercial demonstration of advanced nuclear reactor technology. It calls for DOE consultation with the Commission both before and after the Secretary issues a draft request for construction proposals and provides that the Secretary recommend to the

Commission any changes in Commission regulations which would assist in the licensing process. Section 12008 requires that, within two years after selection of a proposal, the Commission submit to Congress any recommendations for legislation needed to facilitate the licensing of commercial advanced reactors. This section also requires that the Secretary of Energy report to Congress and the Commission on the development of advanced reactors technologies in other countries, and that the Commission report to Congress on the licensability of any such technology that the Secretary's report recommends.

Title XIII of the bill would augment the Commission's ability to limit the opportunity for a post-construction licensing hearing. Under the legislation, a facility which has been issued a combined construction permit and operating license would be permitted to operate notwithstanding the pendency of a request for a preoperational hearing unless a showing is made that (1) there exists a substantial dispute of material fact that has not been considered by the Commission and that cannot be resolved except at a hearing and (2) a showing has been made that there has been a nonconformance with the combined license that has not been corrected and that could materially and adversely affect the safe operation of the facility. The bill's language, found both in Title XII and in Title XIII, would essentially codify the one-step licensing process the Commission adopted in Part 52.

The U.S. Court of Appeals affirmed the provisions of Part 52 that institute combined construction permits and operating licenses and provide for design certification and early site approval. The only portion of Part 52 which the Court invalidated was the provision which limits the opportunity for a post-construction hearing to the question of whether the acceptance criteria in the combined license have been met. The Court found that the Atomic Energy Act requires the opportunity for a post-construction hearing to encompass any significant new issue concerning conformity with the Atomic Energy Act. The Commission, with the support of the Department of Justice, has filed a petition for rehearing of that decision. A copy of that petition is attached to this testimony. If the Court denies the petition, the Commission will consider seeking Supreme Court review.

As we have argued before the Court, the Commission continues to believes that the Atomic Energy Act gives us ample authority to promulgate Part 52 as written. The Commission believes that this view may ultimately prevail before the courts.

In summary, the commission believes that the bill's language would essentially codify the preoperational hearing process that the Commission adopted in Part 52. Hence, the Commission would have no objection to enactment of this legislation.

NATHANIEL D. WOODSON

Vice President and General Manager
Energy Systems Business Unit
Westinghouse Electric Corporation

Nat Woodson is vice president and general manager of the energy systems business unit of the Westinghouse Electric Corporation. Appointed to this position in November 1990, he is responsible for the firm's commercial nuclear power generation activities.

Mr. Woodson joined Westinghouse in 1966 as a systems engineer with the atomic power division. Following a series of key project management positions in nuclear energy systems, he was named vice president of projects for Westinghouse Nuclear Europe in 1975.

In 1977 he was named president of Westinghouse Nuclear Espanola in Madrid, Spain, and in 1981 became general manager of Westinghouse Nuclear International, headquartered in Pittsburgh, Pennsylvania. In 1982 he was appointed general manager of the Westinghouse nuclear operations division.

Mr. Woodson became general manager of the Westinghouse energy systems technology divisions in 1986, and in May 1988 was appointed general manager of the nuclear fuel business unit in Monroeville, Pennsylvania. He was named President, International in March 1989 and in the same month was elected a Vice President of the corporation.

A 1963 graduate of Yale University with a B.S. in mechanical engineering, Mr. Woodson also holds a masters degree in nuclear engineering from the Massachusetts Institute of Technology and an M.B.A. from the University of Pittsburgh. In 1980, Mr. Woodson completed the Advanced Management Program at the Harvard University School of Business.

I'm Nat Woodson. As vice president and general manager of the energy systems business unit of the Westinghouse Electric Corporation, I am responsible for managing the firm's commercial nuclear power activities. And I'm no stranger to the nuclear industry ... having worked in this business for all but 27 months of my 25 year career.

Since its founding in 1886, Westinghouse has been one of the world's foremost providers of electrical energy technologies. In fact, during our 105 years in business, we've supplied over 270,000 megawatts of power generating capacity in 45 countries. We pioneered nuclear energy with the design of Shippingport, America's first nuclear power plant, in 1957. Since then, more than half of the world's nuclear plants have been based on our Pressurized Water Reactor (PWR) technology.

More than 30 years ago, spurred by the "Atoms for Peace" plan, the electric utility industry embarked on the technological challenge of harnessing the atom for the generation of electric power. The visionaries that pioneered the nuclear power industry recognized the promise of reliable, low-cost power. That promise of nuclear power is one we can still fulfill. And, Westinghouse remains -- as always -- committed to doing its share.

Today, Westinghouse shares the utility focus on total quality and operating plant performance. We all understand that sustaining excellence in plant performance is the real road to reliable, cost-effective and environmentally sound electricity from the atom ... and the road to the next era of nuclear power in the United States.

Our industry focus on operations is paying off. Nuclear plant performance in the United States has improved dramatically. According to the Institute of Nuclear Power Operations (INPO), in 1989 the average U.S. nuclear plant availability factor set a record of 62.5 percent. And, radiation exposure per unit declined. What's more, this trend is continuing. In 1990, the availability factor for 51 Westinghouse plants was 74.3. This is a positive sign.

And there are other positive signs. We applaud the DOE's long and rigorous efforts to develop a National Energy Strategy. The results are significant. As President Bush stated, "...it is a strategy for an energy future that is secure, efficient and environmentally sound." And, we strongly support initiatives on standard plant designs, licensing reform, and accelerated advanced reactor funding. These initiatives recognize the importance of nuclear power in a balanced energy plan.

Nuclear power's importance to our nation's energy future is further recognized in the Nuclear Power Oversight Committee's (NPOC) strategic plan for new nuclear plant construction. We at Westinghouse believe that all these initiatives are important to renewing the promise of nuclear power.

Nuclear Power's Role in Our Energy Future

Our National Energy Strategy enables us to establish an energy base that's optimal from economic, security and environmental perspectives. Electricity from nuclear power -- an energy source which is efficient, cost-effective and environmentally clean -- has an important role to play in this energy future.

As an energy form electricity is extremely flexible ... generated from many sources ... easily adaptable to user requirements ... and in many cases a direct substitute for oil. And, it fuels many common but critical components of modern life.

In this country, electricity demand generally grows at about the same pace as the economy. But throughout much of the 1980s, actual electricity demand outpaced forecasted demand by 1.5 percent per year, on average. Should this situation continue, in just a few years capacity margins could drop below the levels generally recognized as acceptable. Such an event would increase the likelihood of reliability concerns in many regions.

At 2.6 percent per year growth, DOE forecasts that more than 126 thousand megawatts of new capacity will be needed to meet the electricity requirements of 2000. Utilities throughout the country are evaluating alternatives for installing new capacity. But many are wary of being left with excess capacity should demand slow, and so are reluctant to consider building large central station power plants. Today, gas-fired combustion turbines and combined cycle plants are being used to satisfy peaking, intermediate, and in some cases baseload capacity needs.

But by the late 1990s, substantial investment in new baseload power generation will be required. Nuclear power can provide a prominent source of this baseload power. Plant life extension programs will enhance the service availability of current facilities and plant operators will strive to continue to enhance plant safety and reliability. And, new designs will provide simpler, safer and more reliable next-generation technologies.

Industry Responses: Renewing the Nuclear Option

Today the industry remains committed to moving forward with the nuclear option. We're completing the current generation of reactors and intensifying our research and development efforts in order to hasten the commercialization of new designs.

I'll talk more about these concepts later. But for now, let me stress that costs for these engineering efforts must be borne by a broad portion of the industry -- including the federal government.

AP600 Update

Westinghouse believes in the future of nuclear power. We're actively and aggressively pursuing a renewed nuclear option through the development of simpler, more affordable reactor designs. But then, moving toward greater levels of safety, economy and reliability has always been the guiding principle behind Westinghouse technology development. Now, two major design programs have culminated in the most economical nuclear power plants available: the advanced pressurized water reactor (APWR) and our advanced, naturally-safe design, the AP600.

The APWR program involves Westinghouse and five Japanese utilities, and has produced a fully tested and validated state-of-the-art 1350 MWe plant. This design, referred to as the SP/90 (Standard Plant for the 90s) has received U.S. NRC design approval in letter form. Formal design approval is imminent.

The AP600 is our DOE/EPRI sponsored design for an advanced passive 600 MWe plant. Its smaller size allows capacity to be added in increments that match demand growth more precisely than is possible with larger facilities. The AP600 is also extremely competitive with other generating sources. Our analyses show that the overall capital cost for the plant should register at about half the cost per kilowatt of some recently constructed nuclear facilities.

These savings derive from simplification, modularization, and extensive reference plant experience. The simplified design of the AP600 saves material and space. And, safety systems which rely on natural phenomena for their operation result in massive reductions in piping, valves, cables, pumps and heat exchangers. Modular construction techniques also reduce building time and costs.

U.S. utilities are leading an industry-wide effort to establish the technical requirements for the design of the Advanced Light Water Reactor (ALWR). The extraordinary database of information garnered throughout 30 years of operations at 111 light water reactors in the this country, and many more overseas, forms the foundation for the ALWR program. This effort -- undertaken in close cooperation with the U.S. Department of Energy -- is managed by the Electric Power Research Institute (EPRI) and includes the participation of several international companies.

But important challenges remain before a renewed commitment to the nuclear option can be fully realized. Plants must continue to be operated to incorporate lessons learned throughout over 5000 reactor-years of commercial operations worldwide. And federal and state regulatory processes must be made stable and predictable to reduce the financial risks of new construction.

Significant progress toward resolving these issues is needed before firm orders for the next generation of nuclear plants can be expected. In response to this need, NPOC has developed a strategic plan for ordering and building new plants by the mid-1990s. The plan identifies all the conditions necessary to achieving this goal and sets a timetable for their implementation. And, in focusing attention on these enabling conditions it fosters coordination and cooperation between government and industry.

We at Westinghouse are pleased to have played a part in the development of the NPOC plan. And, we're encouraged by the growing acceptance of the plan, and its synergy with the National Energy Strategy.

The NPOC plan also endorses the concept of standardization which EPRI has promoted through its ALWR program requirements. But achieving this level of standardization is dependent on extensive first-of-a-kind engineering and reactor designs which are certified by the NRC. And, concurrent with these efforts, industry must proceed with an early site permit program to qualify construction sites at the earliest possible date.

But perhaps most importantly, the AP600 technology is grounded in a proven pressurized water reactor (PWR) technology base that has been demonstrated throughout decades of successful operation around the world. The AP600 is the optimized progression from the Westinghouse two-loop, 600 MWe PWRs that consistently achieve availability factors that are 10 percent higher than the national average. And, because it is based on the world's most widely used nuclear power technology, the AP600 is a mature design that will not require a demonstration plant for NRC licensing or investor utility confidence.

The AP600's technical successes are impressive. The design is in full conformance with current NRC and EPRI requirements for advanced, naturally safe reactors. With 100 percent of the conceptual design effort finished, the AP600 is ready to undergo detailed design, rigorous NRC review, and design certification.

The next step, already underway, is a $120 million, cost-shared, program to perform detailed design for a Standard Safety Analysis Report-(SSAR) and for final design certification from the NRC. Last February the DOE awarded us a $50 million cost-sharing contract to continue this design and development effort. Westinghouse has also signed a six-year, $22.5 million contract with EPRI that represents a sizeable utility investment in our technology.

The SSAR is scheduled for completion by mid-1992. Final approval of the design by the NRC staff is expected at the end of 1993, so that by December 1994 the AP600 will receive design certification from the NRC. The Westinghouse AP600 will be the first simplified, naturally safe plant submitted for certification under 10 CFR Part 52.

We'd like to bring the first AP600 on-line by 2000. As part of our Lead Plant Strategy Program -- which uses the AP600 as a model plant for stepped-up development -- we'll continue to foster a high level of cooperation with utilities to realize our common goals. Following this lead plant strategy, key activities such as site certification and completion of first-of-a-kind engineering are undertaken in parallel rather than sequentially. This approach should enable us to bring the first AP600 to commercial operation by the end of the decade.

Currently, an advisory committee of senior utility executives is working with us on the lead plant implementation strategy. Utilities also attend our workshops where we seek feedback on the responsiveness of our design. And, we find significant support for our ALWR program in the NPOC strategic plan -- in fact, our lead plant strategy complements the approach taken in the NPOC plan.

Current Actions

As I've mentioned earlier, the National Energy Strategy sets the framework for the commercialization of advanced reactor technologies. To implement this strategy, DOE has given priority attention to the ALWR program. Commensurate with this program, DOE has increased the funding support to vendors for activities necessary to achieve timely certification of advanced designs. For these designs to be market-ready in time to meet the demand for new baseload capacity, DOE is focusing on actions that can facilitate new plant orders by 1995.

We at Westinghouse share DOE's commitment to maintaining the momentum of the ALWR program. And we endorse those actions aimed at averting electrical reliability issues in the 1990s and beyond. Four of these actions are key: licensing reform, design certification, the early site demonstration program, and first-of-a-kind engineering. Let me take a moment to talk about each of these items in turn.

Licensing Reform. Predictable licensing and stable regulation are needed to reduce the financial risks associated with new nuclear plant construction and operation, and to enhance the public's ability to address valid safety questions early in the licensing process. The NRC has made significant progress toward resolving this issue through its enactment of 10 CFR Part 52. This regulation enhances plant safety, furthers standardization, and adds stability to the regulatory process. It limits the issues in any preoperational hearing to a determination of whether the plant was built in conformance with the provisions of the combined license. Importantly, the NRC retains its traditional authority to amend the combined license should any new safety information arise.

However, last November, a federal court ruled that although Part 52 responds to "the industry's changing knowledge and the public's changing needs," only Congress could limit preoperational hearings to the extent detailed in Part 52. Since then, with the support of the Department of Justice, the NRC has requested that the Court reconsider its decision.

We would welcome legislative action that clarifies the NRC's authority to limit the scope of a second hearing to conformance issues and to allow the NRC to take such a hearing off the critical path ... without compromising opportunities for meaningful public participation. Part 52 greatly expands the scope of technical information required of applicants. It requires an essentially complete design and all necessary information for the NRC to make safety findings. And, through the preparation of stringent requirements for Inspections, Tests, Analyses, and Acceptance Criteria (ITAACs), it enables plant constructors to provide reasonable assurance that a plant which references a certified design is built and will operate in accordance with that design.

Design Certification. DOE is also sponsoring plant design certification efforts for ALWRs under 10 CFR 52. These efforts are closely coordinated with the ALWR program so that vendor submittals to the NRC are consistent with utility requirements. These interfaces permit designers, constructors and regulators to work together to obtain a fully integrated design which meets safety, performance, constructability and economic criteria. And, the NRC is committed to allocating resources to conduct a thorough review of each design submitted for certification.

Design certification is an essential prerequisite to new plant construction. Westinghouse is participating in the current DOE program to advance the AP600 to a certified design. This program calls for developing plant designs with a level of detail required by 10 CFR Part 52. On February 15, 1991, the NRC signed a staff requirements memorandum (SRM) for SECY-90-377, "Requirements for Design Certification under 10 CFR Part 52." These requirements are, on the whole, consistent with the level of detail defined in the AP600 design certification program.

EPRI is supporting our AP600 design certification effort. And we're working closely with EPRI to ensure that the AP600 design satisfies all the criteria for passive plants found in the ALWR Utility Requirements Document currently under review by the NRC.

Early Site Demonstration Program. 10 CFR 52 also provides for the issuance of early site permits. Such permits contribute to a stable regulatory process by allowing early resolution of site-related issues before the combined construction permit/operating license hearings and before utilities have made significant capital investments in the construction process.

We welcome DOE's initiative to demonstrate the feasibility of this approach by obtaining an Early Site Permit for a U.S. site for one or more ALWRs by the end of 1994. We also support the industry efforts underway to respond to DOE's request for proposals for the "Advanced Light Water Reactor Early Site Permit Program." Westinghouse will cooperate in this program by providing the AP600 design parameters so that our design satisfies the requirements for site certification.

There is no question that the nuclear business is changing. As utilities complete construction of the current generation of nuclear plants, the primary industry focus has shifted to maintaining operational excellence. The reasons are twofold: so that utilities receive a sustained return on their investments, and to pave the way for the next generation of reactors.

We can expect significant changes in the way these next generation facilities are designed, licensed, constructed and operated. Final design for next generation reactors will be completed before construction begins. Cost and schedules will be firm. Field construction practices will give way to a modular approach. And, licensing reform and regulatory preapprovals will add much-needed stability to the regulatory process while providing the opportunity for meaningful public participation before substantial investment capital is committed. The Nuclear Energy Strategy initiatives, the NPOC building blocks, and the Department of Energy's fiscal year 1992 funding requests all recognize and respond to these changes.

First-of-a-kind Engineering. First-of-a-kind engineering for advanced reactor designs will play a major role in the new nuclear industry. It provides the certainty required by the utility industry before committing to new orders. And it is critical to achieving industry goals of standardization. So, together with design certification and early site demonstration programs, completing first-of-a-kind engineering will provide the insurance policy that we need so that the next generation of reactors is available for orders in 1995.

Cost and schedule assurance is a top priority -- and a prerequisite for new plant construction. Through first-of-a-kind engineering, all nonrecurring, first-time engineering will be completed up-front, opening the door to firm price and schedule offerings.

Let me restate that in practical terms. When first-of-a-kind engineering is completed, Westinghouse and its partners could offer a turnkey proposal for the AP600 that provides specifics project costs, completion date, and performance.

Achieving cost and schedule certainty is significant in a very real financial sense. By avoiding overruns and agreeing to a design in advance of construction, the probability of regulatory disallowances is greatly reduced. And that will result in considerable savings. In the 1980s, for example, Public Utility Commission disallowances for schedule delays and cost overruns at 23 nuclear units totaled $7.2 billion. That's about $320 million per unit. These figures dramatize the impact of cost and schedule uncertainties, and clearly illustrate the benefits of first-of-a-kind engineering.

First-of-a-kind engineering will also facilitate the modular engineering approach needed for new, more cost-effective construction. Plants will be built through factory-produced modules that can be erected at the site in only 36 months ... a process that also substantially enhances our control over quality. A detailed design package supplied prior to the onset of construction will lead to many advantages with little or no risk:

- Firm quantities of construction materials
- Firm and advanced construction planning and scheduling
- Firm estimates of construction labor and field supervision
- Firm module designs and elimination of nonrecurring engineering

Finally, first-of-a-kind engineering so completely defines plant details that only equipment procurement and site specific design work remains. Therefore, first-of-a-kind engineering -- coupled with design certification -- results in a standardized design.

A comprehensive industry commitment to standardization is one of the key elements of the NPOC strategic plan. This commitment exists because industry has long recognized the economic advantages of standard designs. France provides the most obvious example. Although standardization had been on a much smaller scale here in the U.S. (with projects such as SNUPPS), the clear advantages of large-scale implementation have been recognized:

- Regulatory stability and elimination of unnecessary changes through early definition of requirements
- Resolution of issues in a timely and systematic manner
- Design optimization
- Simple and uniform designs that are easier to build and operate
- Focused and efficient application of technical and financial resources
- An expanded resource base that enhances support capabilities
- Accelerated, maximized feedback from past experience

To ensure utilities are provided with a continuing, renewed nuclear option by the mid-1990s, first-of-a-kind engineering must be initiated in 1991. We fully support the DOE initiative for a cost-shared program on first-of-a-kind engineering. And we urge Congress to approve the $20 million budgeted for this program in fiscal year 1992.

Summary and Conclusion

We all know that we're getting closer to the point where decisions will have to be made about large central station power plants. In a balanced energy picture, some of those plants should be nuclear.

The National Energy Strategy points to the need for expanded baseload electrical capacity at the outset of the next century. And, the DOE's fiscal year 1992 funding request places priority on those actions which would enable new plant orders to begin by 1995. We urge Congress to support the funding request for the ALWR program and the increased funding for design certification.

Licensing reform is critical. We support the licensing reform initiatives contained in the National Energy Strategy, and urge Congress to support legislation that clarifies the NRC's authority to limit hearings after a plant has been built.

Completion of first-of-a-kind engineering is also critical . It responds to the imperative of cost and schedule certainty and contributes significantly to the objectives of standardization. We welcome the DOE initiative on first-of-a-kind engineering and ask your support for the fiscal year 1992 budget request of $20 million.

Taken together, the combination of first-of-a-kind engineering, design certification, and early site certification -- all completed by the mid-1990s -- will enable utilities to embark on a new generation of simple, standard, more economical nuclear power plants. And, of course, it's crucial that we continue our commitment to performance excellence at today's operating power plants.

The facts are plain ... significant progress is being made toward renewing the nuclear option. The National Energy Strategy sets a positive framework. DOE, EPRI and the industry are rapidly advancing the technology through continued strong support from Congress. And, NPOC has developed a solid plan whose goals can be achieved through cooperation and collective action.

Westinghouse values its long association with the Department of Energy on programs of national importance. We view nuclear programs in this manner, and we welcome this opportunity to discuss their role, and our role, in supporting our nation's vital interests.

Thank-you.

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ASEA BROWN BOVERI

March 22, 1991

The Honorable J. Bennett Johnston
Chairman, Committee on Energy & Natural Resources
U. S. Senate
364 Dirksen Senate Office Building
Washington, DC 20510-6150

Dear Senator Johnston:

Thank you for the opportunity to provide written testimony on S.341, the National Energy Security Act of 1991. I would like to commend you and Senator Wallop for including nuclear energy in a comprehensive program for addressing this nation's energy needs.

Your invitation specifically requested that I provide my company's views on whether the provisions of Titles XII and XIII will encourage the development and commercialization of advanced reactors that may be safer, less costly, and easier to build and operate than the present generation of plants.

As I have testified to Congress on a number of occasions, the major obstacles to restoring the nuclear option in this country are institutional -- not technological -- in nature. Therefore, the near term activities of government and industry should emphasize developing solutions to those institutional obstacles. Development of new technologies tends to be much more costly and to require much greater time spans to complete.

No single technology best meets all of the criteria proposed in S.341. We should pursue some degree of development for each of the proposed reactor technologies now being supported by DOE. For the near term, the Evolutionary Advanced Light Water Reactors, e.g., our System 80+ standard design, provide the proven track record that utilities need to resume nuclear plant construction. In the long term, the Modular High Temperature Gas Cooled Reactors and the Liquid Metal Reactors may provide the high thermal efficiencies and fuel efficiencies needed to keep nuclear energy an attractive source of electricity well into the twenty-first century.

ABB Combustion Engineering Nuclear Power

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Section 12003 should be revised to avoid overly prescriptive criteria for advanced reactors. For example, to address public concerns, it is important that new nuclear plants be significantly safer. How the improvement in safety is achieved is not the issue. Therefore, the bill should not include terms like "passive" safety features. Industry studies are showing that "active" safety systems will provide higher levels of safety than the so-called "passive" safety systems. We should be providing the American people with the best technology available, at the time it is needed. We should not be fooled into requiring features that only look more attractive on the surface.

It is good that the bill provides for Design Certification in Section 12003, promotional support of projects by the Secretary in Section 12005, and Licensing Reform in Section 12005 and Title XIII. These all address institutional obstacles.

Providing for Certified Designs is probably the most important feature of the bill. Regulatory instability is the most serious problem facing the resumption of nuclear energy plant construction, and it is on the critical path to regaining utility confidence. Furthermore, the DOE program to certify the two Evolutionary ALWRs is relatively inexpensive.

The provision in Section 12005 that authorizes the Secretary to "be responsible for the costs of any new requirements imposed by the Commission after issuance by the Commission of a license" is also an important feature of the bill. It will provide the first utility applicants to order nuclear plants with confidence that they will not become the "guinea pigs" for testing the new 10CFR52 licensing process for a Combined Construction Permit & Operating License.

The licensing provisions in Section 12005 and Title XIII are equally important in providing the regulatory stability that is needed for future nuclear plants. Although the bill proposes a stringent standard for granting a second hearing, another desirable feature would be to allow the hearing to be held off of the critical path to plant start-up -- assuming that a substantial safety hazard does not exist.

Section 12006 calls for construction of a demonstration project. Government support for such an activity could easily drain funding away from the other programs just mentioned and, therefore, should not be entered into any time soon. Such a project is not required to restore the Light Water Reactor option and should not be needed for the other advanced reactor options for many more years. The HTGR New Production Reactor will eliminate the need for a civilian MHTGR demonstration, and the ALMR will not be ready for demonstration for quite some time. Therefore, I believe that Section 12006 could be deleted from the bill -- or at least significantly delayed, in its implementation.

Finally, I note that the funding provided in Section 12007 is $100 million in FY-93 and $200 million in following years. Depending on how the Secretary defines the programs to be proposed under this bill, $100 million could actually be a reduction from the current Nuclear R&D budget. I would recommend that the level be raised to $200 million in FY-93. Even then, such levels would only be adequate if my recommendation about deleting Section 12006 (or delaying it for several years) is implemented.

I hope that you find my suggestions helpful. With these changes, I believe that S.341 would be a very important vehicle for restoring the nuclear option and assuring its continued health.

If you would like to discuss these issues further, please feel free to call on me.

Sincerely,

Shelby T Brewer

Shelby T. Brewer

STATEMENT FOR THE RECORD REGARDING:

SENATE 341: NATIONAL ENERGY SECURITY ACT OF 1991

COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

LINDEN S. BLUE
VICE CHAIRMAN
GENERAL ATOMICS

MARCH 22, 1991

Introduction & Summary

As Vice Chairman of General Atomics and someone who has been involved in oil and gas as well as international trade and high technology, I am very pleased to have the opportunity to comment on the proposed "National Energy Security Act of 1991." I agree completely with sponsors of the bill concerning the need for a national energy strategy which will reduce oil imports and increase the fraction of our goods, services and energy which are truly "Made In America." I, along with almost everyone I know, am in complete agreement with efforts to increase our energy efficiency and our use of renewable energy forms in all economically prudent ways. In my opinion, S.341 would go a long way toward achieving these and other important goals.

I support the broad objectives of the bill, but I will focus my comments on Titles XII, XIII and XIV which are most crucial to our domestic nuclear energy industry. Title XII, the "Civilian Advanced Nuclear Reactor Act of 1991" provides a framework to allow industry to breathe some life into the dormant domestic nuclear power plant market. The programs proposed in Section 12005 and 12006 will encourage industry to move forward with new projects but will, in my opinion, require some strengthening. Specifically, industry can accept the cost of risks over which they have control, but cannot accept the risks of national policy changes. I therefore believe that the government must provide private investors with protection from changes in government policy which adversely impact the value of their investment. Without such indemnification, private sector investment in these projects cannot be deemed as prudent.

Under the Advanced Reactor Commercialization proposed in Section 12006, the proposed technologies are to be evaluated with respect to several important characteristics including safety, waste, and public acceptability. The advanced reactors do much to address these issues but can do more if properly challenged. I would suggest that at least two additional evaluation characteristics be added. First, advanced reactors can offer the elimination of accidents with severe public consequences. Core melting and substantial fission product release can be precluded by appropriate selection of materials, power density and core size. The "China Syndrome" imagery can be exorcised from advanced nuclear power facilities. Second, advanced nuclear reactors can provide the higher outlet temperatures required to increase the thermal efficiency for conversion to electricity. In addition, the next generation of plants can produce steam and gas temperatures high enough to allow nuclear energy to displace much of the fossil fuels employed for this country's process heat. Advanced reactors could eventually provide the energy necessary to convert domestic coal to clean-burning portable fuels. The bill should encourage the industry to pursue these additional characteristics by including them in the evaluation criteria.

Title XII should also be clarified with regard to the relationship between the proposed commercialization funds and the existing DOE research and development programs. The bill addresses only reactor commercialization and my understanding is that the funding proposed by the bill is meant to be in addition to the existing DOE R&D programs. I also hope that commercialization projects for more than one technology will be possible under the bill. Consideration should be given to all projects which provide sufficient value to be attractive to the nation.

I concur with the provisions of Title XIII and XIV. Regulatory hearings following issuance of a construction permit should be confined to substantial issues and not be allowed to be a primary means of delaying and financially crippling a safe, sound project. The uranium enrichment industry must be restructured and eventually privatized if we are to have any hope of reversing the dramatic loss of world market share which we have experienced over the last decade. The provisions of Title XIV are a positive step in that direction.

Senate 341 can do much to reduce our dependence on foreign oil. Improved efficiency and increased use of renewable energy sources and nuclear power can play an important role. The commercial demonstration of advanced nuclear reactors supported by the bill could also be the vehicle which catalyzes an advanced reactor technology which permits the U.S. to return to its role as a major competitor in the international nuclear energy market. "Made in America" could appear on a new generation of safer, more efficient nuclear power plants in the U.S., as well as around the world.

Nuclear Policy Indemnification

The private sector will have difficulty in attracting investment funding if the investment requirements and risks cannot be firmly established and the prospects for a reasonable return adequately assured. Unfortunately, there have been several instances in the development of the U.S. nuclear power enterprise in which substantial private investments have been sacrificed as a consequence of national policy changes. The frequency of occurrence and magnitude of loss have been sufficiently high that it is extremely doubtful that private sector investment could be attracted without provisions for indemnification of losses resulting for such policy changes.

Advanced Reactor Criteria

Consideration should be given to adding an evaluation criterion which addresses the potential for advanced reactor technologies to effectively eliminate severe accidents involving core melt and the resultant release of radioactivity. Although it has been repeatedly shown that the probability of severe accidents with current U.S. commercial nuclear plants is small, the public does not have high confidence that nuclear power is safe. The term "nuclear power" in the public's mind is not clean, safe, economical power enabling a high standard of living, but rather TMI and Chernobyl. The evaluation criteria should, accordingly, contain criteria which address this public perception. I believe that a criterion which addresses the elimination of severe accidents is appropriate for advanced reactor technologies.

A criterion is suggested to be added for advanced reactor technologies which addresses the potential for increased efficiency and eventually for displacement of fossil fuels in sectors other than electricity generation. Higher efficiency conversion of primary energy to electrical power can be obtained in advanced reactor systems with higher reactor outlet temperatures. Initially, with higher reactor outlet temperatures, higher efficiencies can be obtained using the steam cycle. With sufficiently higher outlet temperatures using gaseous heat transport, Brayton cycle gas turbine energy conversion efficiencies approaching 50% are achievable.

Only about one-third of the total primary energy use in the U.S. is for the generation of electricity. (About one-third is used for space heating and in industrial processes and about one-third is used for transportation.) The primary energy sources are predominantly the fossil fuels (coal, oil and gas); nuclear is now contributing but only in the electricity generation sector. The use of fossil fuels is causing acknowledged threats to the local and global climate, i.e., acid rain and global warming. The further development of nuclear power has the potential to substantially reduce these threats by displacement of the fossil fuels. The development of advanced reactor technologies should not be focussed exclusively on the electricity generation sector. The development expectations for advanced reactor technologies can be further justified by the potential to make substantial reductions in the use of fossil fuels in all of the primary energy use sectors. An evaluation criterion is, accordingly, suggested that addresses the potential for increasing electric generation efficiency and for displacing the use of fossil fuels in other than the electricity generation sector.

Clarifications

A clarification is suggested regarding which reactor technologies Section 12005 and 12006 are addressing. The inference is that Section 12005 is addressing those technologies which are expected to become certified in the near term (i.e., before the year 2000). Whereas, Section 12006 appears to address those technologies which have not had prior commercial scale demonstration. Clarification of the bill language would be helpful.

The commercialization funds in Title XII are understood to be in addition to the existing DOE R&D programs. A clarifying statement is suggested which indicates that the commercialization funds are for deployment of commercial scale plants, to demonstrate the technology, and to develop the supply infrastructure and as such are in addition to the funds for technology and design research and development in the existing DOE R&D program.

A clarification should be added which indicates that the bill is not limited to a single technology commercialization project. Consideration should be given to all projects which provide sufficient value to be attractive to the nation. A clarification is suggested that acknowledges the potential for the support of more than one project under Section 12006.

Bechtel
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Washington, D.C. 20005-2605

March 22, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate - SH-136
Washington, DC 20510-1802

Dear Senator Johnston:

We thank you for the opportunity to provide Bechtel's comments on Titles XII and XIII of S.341, the National Energy Strategy, Security Act of 1991. These nuclear energy provisions of the Act are most important to the United States. Our comments are as follows:

1. The overall tone and intentions of Titles XII and XIII are positive and encouraging.

2. The language of both Title XII section 12005.f.(1).D and Title XIII section 13002 regarding limitations on the conditions under which a second hearing would be granted is a simplifying improvement compared to the current language in 10CFR52. This language would establish a statutory basis for NRC to use true one-step licensing. This would allow the process to be better able to withstand court challenge than the current 10CFR52 and the Atomic Energy Act.

3. Section 12006 of Title XII calls for a 50% cost sharing on proposals for an ALMR or an MHTGR by 18-24 months after enactment. This is not likely to happen as the remaining licensing uncertainties will be too large for these advanced concepts, at that time, to attract hundreds of millions of dollars in private sector participation.

   For these advanced non-LWR concepts, the NRC requires a full-scale, integrated prototype test to support certification. The cost of such a prototype (single 155-170 MWe module project), including the first-of-a-kind costs, is in excess of $800 million (in 1990 dollars). The cost of fuel, and of operation and maintenance, for such a prototype are likely to be greater than the equivalent costs for a coal plant. Hence the economic value in terms of capital cost for such a module is likely to be less than

$1500/kWe, or less than $250 million in total project cost. This leaves over $550 million for the government. On the basis of this probably optimistic analysis, the private sector may be able to contribute about 30% (250/800) but not 50%. A more realistic split is probably 20% for the private sector.

If you have futher questions on this matter, please have your committee staff contact me or William D. Craig, at (202) 393-4747.

Sincerely,

Thomas L. Mack

STATEMENT
on
THE NATIONAL ENERGY SECURITY ACT OF 1991, S. 341
for submission to the
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
for the
U.S CHAMBER OF COMMERCE
by
Jeffrey H. Joseph[*]
March 12, 1991

The U.S. Chamber of Commerce appreciates this opportunity to express its views on the nuclear energy provisions of the National Energy Security Act of 1991 because nuclear power has been and must continue to be a vital and major source of our nation's energy supply. The electricity supplied from the nation's nuclear power plants provides a major contribution to U.S. economic growth, energy security, energy efficiency, consumer well-being, and environmental protection.

Domestic Nuclear Energy Use

As of October, 1990, there were 111 nuclear power plants in operation in the United States, generating more than 20 percent of the nation's electricity supply. Indeed, a number of states rely on nuclear power for more than half of their electricity generation. The states relying most heavily on nuclear energy in 1989 were:

• Vermont	76 percent
• South Carolina	61 percent
• Maine	60 percent
• Illinois	59 percent
• Connecticut	57 percent
• New Jersey	56 percent

Four additional states generated at least 30 percent of their electricity from nuclear energy (Nebraska, Mississippi, North Carolina, and Virginia) and ten additional states generated at least 20 percent of their electricity from nuclear energy (Kansas, Minnesota, Georgia, Arkansas, Pennsylvania, California, Wisconsin, Louisiana, Michigan, and Tennessee).

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[*] Jeffrey H. Joseph is Vice President, Domestic Policy

As the economy grows, the nation's electricity demand is expected to grow as well. According to the U.S. Department of Energy (DOE), the nation will require an additional 250 gigawatts of new electrical capacity by 2010; approximately 85 percent of this capacity will have to be generated by major power plants. Yet no new nuclear power plants have been ordered since 1978, primarily because of the lack of certainty that completed plants will be allowed to begin commercial operation.

International Nuclear Energy Use

Nuclear energy is a growing source of electricity throughout the world. In 1989, nuclear power plants operating in 26 nations generated over 17 percent of the world's electricity. The nations which relied most heavily on nuclear energy in 1989 include:

●	France	75 percent
●	Belgium	61 percent
●	South Korea	50 percent
●	Sweden	45 percent
●	Spain	39 percent
●	Switzerland	37 percent
●	West Germany	37 percent
●	Hungary	35 percent
●	Taiwan	35 percent
●	Bulgaria	33 percent
●	Finland	30 percent

In order for nuclear power to continue to be a major source of energy in this country, a number of vital issues must be addressed: (1) the continued safe design and operation of nuclear power plants; (2) the simplification of the licensing and regulatory process; (3) the restructuring of the United States Uranium Enrichment Enterprise; and (4) the disposal of high-level radioactive waste.

Advanced Reactors

Simplified and standardized advanced reactor designs are essential to improve safety margins, operation, and maintenance procedures at nuclear plants. The Chamber supports the continued research, development, and demonstration of advanced reactor technology, jointly funded by the private and public sectors. Today's reactors are exceptionally complex because of the significant number of safety systems that were added piecemeal to existing reactor designs after the designs were approved -- and often after construction of the plants was completed. The design of most operating nuclear plants varied from utility to utility, and sometimes within the same utility on the same site. Advanced reactors, however, incorporate much simpler designs than the reactors in operation today, and rely on methods such as natural circulation, reduced power density, and materials characteristics to provide safety, leaving as little room for human error as possible. In addition, it is estimated that plants based on advanced reactors would cost approximately $1.2 billion to build, as compared to the $2.7 billion needed to construct a typical 1,000 megawatt power plant today.

Licensing Reform

Advanced reactor designs alone, however, are not enough. We must have a regulatory climate that will assure utility and investor confidence in the feasibility of operating advanced reactors. This confidence can be enhanced through the restructuring of the U.S. Nuclear Regulatory Commission's (NRC) present system for licensing nuclear power plants, which requires nuclear power plants to be licensed twice: first for construction and second for operation. This two-step system has allowed groups opposed to the use of nuclear energy to employ last-minute challenges to delay or block the startup of a completed plant. These delays have contributed to significant cost overruns. As the average construction and licensing schedule lengthened from 5 years during the 1970s to 14 years during the 1980s, average nuclear power plant costs rose from $400 million to more than $3 billion. In addition, many utilities were not permitted to recover these costs through their ratemaking practices.

In April, 1989, the NRC issued a major rulemaking to improve the licensing process. This rulemaking would have permitted the issuance of combined construction and operating licenses. At the end of last year, however, the U.S. Court of Appeals for the D.C. Circuit found that the NRC lacked sufficient statutory authority to limit the scope of a second, pre-operational hearing. At the very least, legislation must be enacted to provide the NRC with this authority. Reduction of licensing time will boost the confidence of the financial community, which must provide the capital needed for further growth of the nuclear industry. More importantly, a reduction in licensing time will benefit the electricity consumer by reducing the costs of construction for new nuclear power plants and reducing the costs of electricity generated from nuclear power. Ultimately, however, the use of standardized, advanced reactors will obviate the need for a second, pre-operational hearing since the safety of these designs will be certified by the NRC.

Two examples of how the current regulatory climate has restricted nuclear development in this country can be found with the Shoreham and Seabrook nuclear power plants.

Shoreham

The 820 megawatt Shoreham reactor on Long Island, New York was ordered in 1967 by the Long Island Lighting Co. (LILCO) Due to delays caused by changes in federal regulations following the Three Mile Island accident in 1979, litigation by anti-nuclear activists, and state and local refusal to participate in emergency planning activities, construction was not completed until 1986. By that time, total costs had skyrocketed to $3.7 billion.

Although licensed by the NRC to operate at full power, Shoreham has never been operated. In 1988, New York Governor Mario Cuomo and the state's Public Utilities Commission pressured LILCO to transfer ownership of Shoreham to the state, which plans to decommission the plant. The NRC must approve New York's plans to dismantle the plant, and has so far refused to do so. In the meantime, this completed plant, capable of generating enough electricity to meet nearly one-third of Long Island's electricity requirements, is standing idle. As a result, LILCO has been forced to import expensive Canadian electricity to meet demand, and has reopened the 112 megawatt Far Rockaway oil-fired plant, an old, inefficient power plant previously shut down in 1980.

Seabrook

The 1198 megawatt Seabrook reactor was ordered in 1972 by Public Service Co. of New

Hampshire. In March, 1990, the plant finally received a full operating license from the NRC, nearly four years after construction was completed. The delay was primarily caused by the State of Massachusetts' refusal to participate in emergency planning activities. In response to this obstructionism, the NRC issued a ruling permitting the approval of emergency plans, which are developed without local participation. Massachusetts contested this ruling in court. Seabrook's evacuation plans were eventually approved by the NRC, and the plant is now operating.

Delays in licensing Seabrook forced Public Service Co. of New Hampshire, the owner of a 36 percent share of Seabrook, into bankruptcy, and cost the utility's electricity customers between $250 and $300 million.

Uranium Enrichment

The availability of competitively priced uranium supplies for nuclear power generation is critical. DOE's Uranium Enrichment Enterprise (UEE) must be restructured to enable it to compete effectively with other suppliers. Since 1975, however, the UEE has gone from a position of near global monopoly in supplying enriched uranium to the non-communist world to a current market share of 45 percent. This share, which is made up primarily of commercial utilities, is maintained solely from long-term contracts, which will begin to expire in 1995. Because DOE's price for enriched uranium is more than double the spot market price, a growing number of U.S. utilities have indicated their intentions to reduce or cancel their future purchases. When this happens, the UEE's already-declining market share will deteriorate further.

The UEE must be restructured in a business-like manner to allow it to achieve success in an increasingly competitive market. The Chamber supports the establishment of a true business enterprise in the private sector. Government should not perform services for itself or others if acceptable privately owned or operated services can be made available. A private entity is the most viable form of business that could compete effectively in the global market, free of the administrative and financial controls that constrain the operational efficiency and financial flexibility of a government agency.

If the UEE is not restructured, the U.S. market will slip away to foreign competitors. With these lost sales overseas will go billions of dollars in positive cash flow that would otherwise have been returned to the United States. A healthy enterprise also would be able to set aside a portion of its revenues for future environmental restoration costs, decreasing the burden on U.S. taxpayers who would otherwise have to pay the entire cleanup bill should the UEE remain in the public sector.

High-level Waste

DOE must determine whether the Yucca Mountain site in Nevada is a suitable repository for high-level waste. Currently, most spent fuel is carefully contained in water-filled storage pools at 72 nuclear power plant sites. Utilities are seeking, and several have received, approval for dry storage of spent fuel from the NRC. This is only a temporary solution, however.

The Nuclear Waste Policy Act of 1982 provided a complete program and schedule to open the nation's first high-level waste repository. The initial completion target date of January, 1998 has already been postponed to January, 2010 because of political, not technical, difficulties. The American Physical Society, the NRC, and the National Academy of Sciences have all concluded that safe, high-level waste management is well within the capability of current science and engineering. Yet, Nevada state officials have refused to grant the necessary environmental permits to DOE to characterize the site, and numerous legal challenges are pending.

The contribution of nuclear power to the nation's energy future depends upon public confidence that high-level waste will be managed safely and reliably. DOE must secure access to Yucca Mountain as soon as possible to determine whether the site can provide the isolation necessary to protect the health and safety of the public and the quality of the environment.

Conclusion

Nuclear energy is the nation's second largest source of electric power, after coal. Yet no new nuclear plants have been ordered during the past 13 years. If nuclear power is to regain its attractiveness to electric utilities and their customers, a number of hurdles must be cleared, including the certification of advanced reactor designs, simplification of the licensing process, and the determination of a safe high-level waste repository.

Nuclear energy is a proven source of electricity with an insignificant impact on the atmosphere. Anti-nuclear activists oppose the use of nuclear energy because of concerns about nuclear waste storage and plant safety. Some of these activists insist that global climate change is inevitable, yet refuse to recognize that nuclear energy is a viable alternative to the use of fossil fuels. They cannot have it both ways.

Energy is an engine of economic growth and the key to U.S. prosperity in a new era of fierce global competition. The nation's economy is based on access to affordable energy. To the extent that we fail to maintain an adequate supply of affordable energy, the price of virtually all U.S. goods and services will be needlessly high, and the nation will continue to lose ground to its international competitors in the global marketplace.

The United States clearly needs new electric generating capacity. Nuclear energy should provide a major share of that new supply.

APPENDIXES TO MARCH 7, 1991 HEARING

(Sections 6003 and 6004 of Title VI and Title X)

Appendix I—Responses to Additional Questions

RESPONSE TO FOLLOW-UP QUESTIONS

SENATOR J. BENNETT JOHNSTON

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE HEARING

MARCH 7, 1991

H. LEIGHTON STEWARD

THE LOUISIANA LAND AND EXPLORATION COMPANY

RESPONSE TO FOLLOW-UP QUESTIONS - SENATOR J. BENNETT JOHNSTON

SENATE ENERGY COMMITTEE HEARING

HELD MARCH 7, 1991

QUESTION 1: To the extent necessary, please supplement your testimony with a more detailed analysis of title II of S.570, the National Energy Strategy Act. Please address both the policy implications of title II and questions raised by the individual provisions of title II.

RESPONSE: LL&E supports the goal of encouraging increased natural gas utilization, including measures similar to title II of S.570 which remove and streamline some of the regulatory impediments caused by existing law. Nevertheless, LL&E believes that any certificate reform legislation should satisfy the following fundamental requirements:

1. Remove current barriers to entry by permitting anyone, not just existing interstate pipelines, to construct "at-risk" facilities;

2. Grant distinct legal recognition of "at-risk" pipelines, i.e., projects which rely on market forces and private negotiation - not regulation - to establish rates and allocate risks.

3. Establish standards of conduct and clear cut procedures which promote and preserve competition among operators and potential shippers on "at-risk" facilities.

LL&E supports the bill's underlying objective of promoting increased availability and usage of natural gas for domestic consumption. Any new natural gas legislation should focus on providing basic ground rules which will promote the construction of new natural gas pipeline facilities on an expedited basis. However, certificate reform is not simply a matter of getting more pipe in the ground, for the cost of inefficient, unjustified construction will be borne by all segments of the natural gas business. The national interest will not be served by a proliferation of economically wasteful facilities, and LL&E therefore recommends a balanced reform package which will promote both competition and efficiency in new construction.

LL&E disagrees with S.570's attempt to restructure the Federal Energy Regulatory Commission (FERC). First, it is difficult to see how incorporation into DOE would expedite the decision-making process. Second, the restructuring proposal would convert the Commission from an independent bipartisan regulatory agency to an arm of the executive branch. Staff input would necessarily increase under a single administrator. The proposed restructuring could further politicize the decision-making process, and remove the current institutional incentive for balanced policy making. LL&E has not always been pleased with the Commission's pace, but speed should be gained by streamlining the existing structure, not sacrificing the Commission's independence.

Finally, LL&E opposes at this time the deregulation of both sales and transportation services as set forth in S.570. LL&E believes that for the foreseeable future most interstate pipelines will continue to possess both monopoly and monopsony power, and that continued FERC oversight is appropriate and necessary. Unlike the "at-risk" pipelines that would be built under the proposed legislation, most existing interstate pipelines were built on an exclusionary basis (i.e., a monopoly) conditioned upon utility-style regulation as provided under the Natural Gas Act. The quid pro quo behind this regulatory "pact" remains to this day and should not be swept aside by deregulation. This does not mean that a lighter handed regulation of the pipelines' services is not appropriate in some circumstances.

In the case of pipeline sales, LL&E has supported negotiated rates where the pipeline has achieved comparability of service on its system. Comparability, however, is a very complex issue on which the Commission only now is beginning to develop its policy and the guidelines for implementing that policy. Many pipelines do not yet offer transportation services that are comparable to sales services. Other related issues, such as the pipeline's service obligation to its customers and customer conversion rights, also remain unresolved on many pipelines. Moreover, in some situations purely negotiated rates may be appropriate for some but not all of the pipeline's customers. In sum, the degree of regulation of the pipelines' sales service remains subject to many interrelated issues which are best resolved through the existing regulatory process at this time.

As to pipeline transportation services, LL&E opposes any form of blanket deregulation at this time. On nearly all interstate pipelines, monopoly power over the transportation service still exists. Even in markets served by more than one pipeline, the market is simply allocated among or between the pipelines. Market allocation does not equate with market competition.

This is not to say that rates on existing interstate pipelines for all services must always be cost-based. However, there still is a need for regulatory oversight of such rates to assure that they are "just and reasonable" and that the market power of the pipeline over its transportation services is not wielded in a discriminatory manner.

If Congress desires to do something on this subject, it should limit its action to affirming or clarifying the Commission's authority to approve negotiated rates when the Commission determines that such treatment is both consistent with the "just and reasonable" and "no undue discrimination" standards contained in existing law.

QUESTION 2: In particular, please address Section 201 of S.570, the so-called mandatory interconnect provision.

a. What are the policy issues raised in connection with this section?

b. Does the section achieve its stated purpose of authorizing the FERC to order upstream interconnection but not downstream interconnection, i.e., bypass?

c. What are the technical questions raised by the manner in which section 201 is drafted? How would you resolve these questions? Please provide suggested substitute language if to do so would be helpful.

RESPONSE: (a) As I testified at the March 7, 1991 hearing, the right of mandatory interconnection is indispensable to any legislation in both the market area and supply area.

In many cases, an entrepreneur's ability to build an at-risk project will depend on access to the established interstate system. A brief example illustrates this point. Assume that natural gas producers discover new supplies which are not presently connected to any interstate pipeline. There are two ways for pipeline service to reach the discoveries. The producers or a third party entrepreneur could build an at-risk facility, or the incumbent pipeline could add an extension.

Assuming that some interstate transportation is necessary to bring the newly found gas to market, the two construction alternatives are competitive with each other only if there is some assurance that the at-risk facility will be interconnected with the incumbent pipeline. Otherwise, the incumbent pipeline can refuse to interconnect, effectively denying access to the interstate grid (and the market) and allowing only the pipeline to build the necessary extension. (There are at least two variations on this theme: the incumbent pipeline might allow the at-risk facility to go forward, but then exact a monopoly rent for the interconnection;

or the incumbent pipeline might attempt to exact a monopolistic price for transporting a gas from or to the interconnection). A pipeline might also refuse to interconnect to preserve its hold on markets at other points on its system.

Mandatory interconnection restores the competitive balance. LL&E advocates an amendment to Section 7 of the Natural Gas Act providing that no holder of a Section 7(c) certificate or operator of an at-risk facility shall refuse to interconnect with an at-risk pipeline if the person seeking interconnection is willing to pay the reasonable cost of the interconnection. The amendment would further require certificate holders or at-risk facility operators to receive, transport and deliver gas delivered from or to an at-risk pipeline.

A certificate holder or at-risk operator would be entitled to insist that a requested interconnection occur at an alternative site, provided the alternative was physically, operationally and economically feasible for the new at-risk facility. Siting disputes would be resolved by the Commission. In a similar vein, a certificate holder or at-risk operator would not be required to expand its system's physical capacity in order to accommodate transportation to or from the interconnection. In addition, no order directing the receipt, transportation or delivery of interconnection gas should divest any existing shippers' contractual rights as embodied in an authorized service agreement with the incumbent pipeline.

(b) As a strong proponent of mandatory interconnection in both the supply and market areas, it would be inappropriate for LL&E to comment on Section 201's effectiveness at serving the contrary purpose of limiting market area access to local distribution companies.

(c) Section 201 should neither expand nor reduce the rights accorded LDCs under the existing Section 7(a) of the Natural Gas Act. LL&E would therefore simply redesignate existing Section 7(a) as Section 7(a)(1).

LL&E would redraft proposed Section 7(a)(2) by inserting " or deliver" after the word "receive". This would ensure equal mandatory interconnection rights in the market and supply areas.

Proposed Section 7(a)(3) should be eliminated. Instead, Section 7(a)(2) should provide that parties should select mutually agreeable sites where possible, and that interconnecting pipelines should not be required to expand their existing system capacity or divest their existing customers' contract rights.

RESPONSE TO FOLLOW-UP QUESTIONS

SENATOR PETE V. DOMENICI

SENATE ENERGY AND NATURAL RESOURCES COMMITTEE HEARING

MARCH 7, 1991

H. LEIGHTON STEWARD

THE LOUISIANA LAND AND EXPLORATION COMPANY

RESPONSE TO FOLLOW-UP QUESTIONS - SENATOR PETE V. DOMENICI

SENATE ENERGY COMMITTEE HEARING

HELD MARCH 7, 1991

QUESTION 1: Do you support the Commission's open access transportation program?

RESPONSE: Yes

QUESTION 2: If sections 204 and 205 of S.570 were adopted what impact would that have on the Commission's open access transportation program?

RESPONSE: LL&E supports measures for allowing entrepreneurs to construct pipeline facilities on an "at-risk" basis in lieu of traditional certification. An at-risk project is defined by the willingness of private parties to respond to market forces and assume market risks. Under the at-risk approach, a pipeline developer and its subscribing customers use arms-length agreements to allocate cost responsibility and share the risks of underutiliziation and cost underrecovery. Non-subscribing customers pay nothing toward the project. Subscribing customers pay no more than they contract to pay.

LL&E advocates establishing procedural options for at-risk development. Under the pre-construction certificate option, the developer would obtain authorization to construct and operate the at-risk facility in accordance with specific statutory standards. Under the non-certificate option, the project would receive neither a construction certificate nor an operating certificate, but the project would be subject to Commission regulations designed to ensure that the project complies with the applicable statutory standards. The pre-construction and non-certificate options share some common elements with sections 204 and 205 of S.570.

Legislation adopting at-risk development will have no impact on the Commission's open access transportation program. The open access provisions set access and rate standards for transportation on "traditional" facilities, i.e., facilities which are certificated under Section 7(c) of the Natural Gas Act (NGA) and which are governed by traditional cost-of-service regulation. In contrast, access and rates for transportation on an at-risk facility are determined by market demands, as measured by customer's willingness to contract for service. Because of this critical distinction, traditional facilities should remain subject to open access regulation.

QUESTION 3: Would you prefer the NGPA section 311 amendments in S.341 or those in S.570?

QUESTION 4: What changes would you recommend be made to sections 203, 204 and 205 of S.570?

RESPONSE: LL&E has generally discussed what amendments we would like to see to section 311 of the NGPA.

LL&E endorses expanding section 311 so that qualifying interstate and intrastate transportation can be provided on behalf of any person. The purpose of this provision was to integrate the interstate and intrastate markets, and this aim is ill served by the court's restrictive reading of the current "on behalf of" standard.

LL&E submits that the vast bulk of interstate pipeline construction would proceed either as at-risk facilities or as traditional facilities. Widespread use of Section 311 construction authority is unnecessary and inappropriate, particularly if notice-and-protest proceedings are made available for traditional projects costing up to $50 million. LL&E therefore urges that interstate pipeline construction under Section 311 should be limited to those minor facilities which are required to interconnect with other facilities providing Section 311 service.

LL&E also notes that there is a debate over the Commission's authority to impose NEPA requirements on Section 311 projects. This debate would largely be rendered moot if Section 311 construction were limited to incidental facilities.

QUESTION 5: S.341 contains an antitrust exemption for marketing coops formed by small independent natural gas producers. Would this help independent producers market their natural gas?

RESPONSE: LL&E believes that legislative measures which afford smaller producers greater flexibility in marketing natural gas would be helpful. Accordingly, we generally support the antitrust exemption for small independent gas producers. We are, however, examining the language to ensure that it contains no unintended consequences for other production operations.

QUESTION 6: Assuming that section 3 of the Natural Gas Act is not repealed and the FERC is not merged into DOE, as has been proposed by the Administration in S.570, would you favor transferring the administration of section 3 from DOE to FERC?

RESPONSE: LL&E agrees that FERC should not be merged into DOE but has no current opinion whether the administration of section 3 should be transferred from DOE to FERC.

QUESTION 7: One difference between S.341 and S.570 is that section 10001 of S.341 would subject persons who construct pipelines under the proposed optional procedures to Natural Gas Act jurisdiction, including the prohibition of discrimination, whereas sections 204 and 205 of S.570 would not. If sections 204 and 205 of S.570 were adopted:

a. Would FERC have jurisdiction to conduct investigations to assure a non-discriminatory level playing field?

b. Could FERC prevent cross-subsidization between jurisdictional and non-jurisdictional pipeline operations?

c. What would prevent a deregulated pipeline from discriminating against, or even excluding entirely, an independent producer, and what remedy would that producer have?

RESPONSE: LL&E is firmly convinced that every person should have an equal opportunity to build and operate at-risk facilities. A market approach to at-risk development will produce more (and more efficient) projects, but only if every producer, marketer and other entrepreneur is left free to participate in the at-risk market. Conversely, any restrictions would necessarily block entrepreneurs from building facilities at their own risk -- a result clearly contrary to expanding the gas pipeline system.

Therefore, LL&E opposes limiting at-risk opportunities to existing "natural gas companies," i.e., incumbent interstate pipelines. Moreover, at-risk development is fundamentally incompatible with many of the regulatory burdens imposed on "natural gas companies" under the NGA, and any definition of at-risk developers would therefore need to identify which NGA sections did and did not apply. With these points in mind:

a. LL&E is confident that more (and more efficient) pipelines will be built if developers and shippers are allowed to allocate project benefits and burdens through private contracts. Given this entrepreneurial setting, at-risk rates should not be subject to the "just and reasonable" standard in the Natural Gas Act or the "Fair and equitable" standard in the Natural Gas Policy Act. Over the years these two standards have become burdened with cost-of-service connotations, and cost-of-service regulation is fundamentally at odds with at-risk development. For example, cost-of-service regulation hampers initiative by imposing significant regulatory costs. (In fact, the only at-risk developers who would not be harmed by the imposition of regulatory costs are the interstate pipelines -- since they are already cost-of-service regulated.) Moreover, the imposition of cost-of-service regulation would deprive the at-risk entrepreneur of whatever benefits might accrue from its negotiated service contracts.

The appropriate measure is whether an at-risk rate is "mutually agreeable." The mutually agreeable rate standard serves two functions, affirming negotiated rates and providing a standard for resolving impasse. The affirmation function cannot be overemphasized. All negotiated rates meet the mutually agreeable standard, and should not be subject to any regulatory oversight, particularly Sections 4 and 5 of the Natural Gas Act.

LL&E strongly believes that negotiation should be the primary mechanism for establishing rates and terms of service. At the same time, LL&E realizes that there may be times when a potential shipper and the operator of an at-risk facility fail to come to terms. A potential shipper should be entitled to file a complaint alleging that the operator has engaged in conduct which in effect constitutes a denial of service. For example, a complaint could allege that the operator has refused to negotiate or that the offered price or terms were prohibitively onerous.

In applying the mutually agreeable standard to an impasse case, the arbitrator should analogize to civil complaints alleging a violation of the essential facilities doctrine of antitrust law. In an essential facilities case, the defendant is entitled to raise any bona fide business justification for withholding access, including the availability of competitive alternatives. While the plaintiff's cost of duplicating the essential facilities is relevant, the defendants cost of providing service is not. Similarly, in adjudicating an access impasse, the potential customer's cost of replicating the at-risk facility (through by-pass or otherwise) may be considered, but the at-risk pipeline's cost of service may not.

Although the at-risk pipeline's cost of service would not be at issue, a range of other facts might be introduced. The filed transportation contracts could be relevant. On the other hand, direct comparisons might be inappropriate for a number of legitimate reasons. For example, the subscribing customers may have been willing to share a greater portion of project risks, or the subscribing customers may be receiving a distinct type of service. Rather than attempting to list all the potential grounds for bringing an impasse complaint (and all the potential business justifications for a particular pipeline operator's actions) legislation should establish a prompt means of resolution and underscore the immateriality of the at-risk pipeline's cost of service.

In resolving an impasse case, the mediator must find a rate that the parties would have agreed to in the absence of the at-risk pipeline's inappropriate behavior. Obviously, this standard carries a wide degree of latitude, as it must to accommodate the variety of impasse cases that might arise. But the emphasis rests on what should not be considered -- the at-risk pipeline's cost of service (or, similarly, the pipeline's projected units of service).

One final word on impasse remedies is important. An impasse dispute is a conflict between the at-risk pipeline and a potential customer. The dispute does not involve existing customers, and their rights should not be affected by a potential shipper's complaint. Therefore, legislation should provide that no remedy in an impasse case may divest any existing shippers contractual rights as embodied in an executed service agreement with the at-risk pipeline.

b. Sections 4 and 5 of the Natural Gas Act would provide the primary safeguard against cross-subsidization.

c. Shippers may seek remedies by filing impasse complaints as described above in response to Question 7(a).

The Brooklyn Union Gas Company
195 MONTAGUE STREET
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ROBERT B. CATELL
PRESIDENT
CHIEF OPERATING OFFICER

718 TELEPHONE 403-3313

April 1, 1991

Honorable J. Bennett Johnston
Committee on Energy and Natural Resources
Dirksen Senate Office Building, Room 364
Washington, D.C. 20510-6150

Dear Senator Johnston:

Thank you for providing the opportunity for me to testify at the recent Energy and Natural Resources Committee hearing on the National Energy Security Act of 1991.

Brooklyn Union endorses the purposes of the Act and is pleased with its balanced approach to reducing our dependence on imported oil and facilitating the continuation of reliable natural gas supplies over the long-run. It is rewarding to see the important role that natural gas can play both in contributing to energy security as well as in improving the environment.

My written answers to the follow up questions you sent to me on March 11, 1991 are attached. We are also preparing written testimony on Title XI -- TRANSPORTATION AND ALTERNATIVE FUELS of S. 341 and will forward it to you shortly.

Thank you, again, for this opportunity to participate in this important process. Do not hesitate to contact me if you require any further information.

Sincerely,

Robert B. Catell

cc: Don Santa, Esq.

ANSWERS TO POST-HEARING QUESTIONS

By

ROBERT B. CATELL
President & Chief Operating Officer

THE BROOKLYN UNION GAS COMPANY

On

TITLE X OF S. 341

THE NATIONAL ENERGY SECURITY ACT OF 1991

April 1, 1991

QUESTIONS OF SENATOR PETE V. DOMENICI

1. **Do you support the Commission's open access transportation program?**

Yes, Brooklyn Union supports the Commission's open access transportation program. We were one of the first local distribution companies to take advantage of open pipeline access and the growing spot natural gas market to purchase lower cost gas supplies.

Open access transportation has produced fundamental changes in the way Brooklyn Union purchases its gas supplies to the benefit of its customers. Traditionally, we purchased all of our gas requirements from pipeline suppliers under a bundled sales service. Today, with the unbundling of pipeline services into separate sales and transportation functions, we can buy gas directly from producers under either spot or long-term purchase agreements, which reflect our market profile. This allows us to better stabilize the price and control the reliability of our gas supplies. Open access transportation has allowed us to diversify our supply sources. We have already converted substantial amounts of pipeline sales service to firm transportation, which has resulted in lower retail gas prices.

One final necessary step is to deal with the issue of "comparability of service" which will enhance open access transportation and provide the necessary operational fine-tuning to open access transportation.

2. **If sections 204 and 205 of S. 570 were adopted what impact would that have on the Commission's open access transportation program?**

We favor the goals of the optional certificate procedures (section 204) and non-jurisdictional option (section 205) of S. 570 to expedite the construction of pipeline facilities, eliminate bottlenecks, expand mainline capacity and storage facilities, enhance open access transportation, and facilitate the further unbundling of pipeline services. However, S. 570 goes well beyond the goals of expediting construction and streamlining the federal regulatory process.

The proposals incorporated in sections 203, 204 and 205 of S. 570 along with the proposals to restructure the FERC and expand the mandatory interconnection authority, result in a major restructuring of the way interstate pipelines currently operate and interact with their customers. The industry has been undergoing major changes during the last five years attempting to implement open access transportation. Imposition of the S. 570 proposals will provide the industry with another period of relatively unstable regulatory policy when what it needs most is now to realize the benefits of open access transportation.

Brooklyn Union favors the Johnston bill (S. 341) noncertificate option and/or the changes proposed in the August 2, 1990 FERC rulemaking (RM 90-1) on pipeline certificates. The Johnston bill would expedite construction under its proposed noncertificate option by, for example, providing for negotiated rates and the elimination of comparative applications. These are changes which will expedite the process without leading to unnecessary uncertainties.

3. Would you prefer the NGPA section 311 amendments in S. 341 D those in S. 570?

Brooklyn Union generally supports revisions to Section 311 as a means of enhancing the competitive market for gas supplies. However, as discussed below, we favor the provisions of S. 341 over S. 570.

Neither of the proposed amendments adequately deal with our concerns of service degradation or possible increased rates. The proposal in S. 570 to provide a state public utility commission with a 30-day notice also does not afford us the opportunity to raise legitimate concerns regarding service degradation (our ability to provide reliable services to our customers) or increased rates. A notice and protest procedure is necessary with the following characteristics:

- o Notice should include a complete description of the project and the reasonably foreseeable impact on rates and service to existing customers. There should be sufficient substance to the filing so that the recipient knows or can determine the impact.

- o The class of protesters would be limited to existing customers of the pipeline who would be impacted by the project.

- o The protest must be accompanied by specific claims of harm and the evidence relied upon to support such claims.

- o The protest would be due in 30 days.

- o The Federal Energy Regulatory Commission should be required to resolve protests in 60 days and should be given explicit statutory authority to resolve protests based on the written submissions.

4. What changes would you recommend be made to sections 203,

204 and 205 of S. 570?

Brooklyn Union is supportive of proposals to expedite the construction of additional pipeline capacity and generally prefers the Johnston bill (S. 341). As to S. 570, it is recommended that an expedited prior notice and protest procedure where issues of service degradation and possible increased rates can be resolved in a timely manner by the FERC, be added to sections 203, 204 and 205. This procedure is detailed in my response to question 3 above.

It is recommended that the new section 7(j) complaint procedures implemented by sections 204 and 205 be eliminated. These procedures allow parties requesting service after completion of construction, who are unable to reach an agreement with the pipeline, to petition the FERC to determine rates and conditions. (see detailed analysis of section 204)

It is also recommended that the provisions of section 204(c)(2), authorizing a pipeline to convert facilities and services previously certificated under 7(c) to 7(i) certificated service, only be permitted if there is an agreement between the pipeline and all affected parties to do so.

QUESTIONS OF SENATOR J. BENNETT JOHNSTON

1. **To the extent necessary, please supplement your testimony with a more detailed analysis of title II of S. 570, the National Energy Strategy Act. Please address both the policy implications of title II and questions raised by the individual provisions of title II.**

   See attached detailed analysis.

2. **In particular, please address section 201 of S. 570, the so-called mandatory interconnect provisions.**

   a. **What are the policy issues raised in connection with this section?**

Brooklyn Union generally supports the expansion of the Commission's authority to order interstate pipeline interconnections, provided that there is adequate protection given to existing services and that legitimate pipeline concerns are taken into consideration prior to the issuance of the Commission's order to interconnect. This Section does raise several policy concerns. The provisions set forth in proposed section 7(a)(3) do not adequately protect existing pipeline service because they do not deal with the complexity of transportation services offered by pipelines. Issues related to existing capacity entitlements, transportation obligations once interconnected, and costs beyond the physical facilities of the interconnection are left unresolved by the proposal. Further, we need to be concerned with the manner in which these issues are to be resolved. If the FERC needs to be involved, it should be in a way that reduces rather than increases its regulatory oversight.

More specifically, while the proposed legislation provides for the payment of physical interconnection costs, it does not address the additional operation expenses incurred by the pipeline as a result of the interconnection. Additional interconnections increase a pipeline's administrative costs relating to dispatching, metering and balancing of the additional gas flows from the new interconnection. These costs currently are rolled-in to the pipeline's cost of service and are paid by all customers. These costs may exceed the rate paid by the party requesting the interconnection resulting in increased rates to other customers. In addition, when assessing the impact of a proposed interconnection on the pipeline's ability to render adequate service to its customers, the Commission needs to examine the impact not only to the point of interconnection, but also on the existing service to all upstream and downstream customers.

b. Does the section achieve its stated purpose of authorizing the FERC to order upstream interconnection

NATIONAL ENERGY STRATEGY ACT

S. 570

TITLE II - NATURAL GAS

Detailed Analysis

Section 201 -- Interconnection Authority

Under the appropriate circumstances, Brooklyn Union would support the expansion of the Commission's authority to order an interstate pipeline to physically interconnect with other facilities to receive natural gas into the pipeline. Such an interconnect would have to be at the applicant's expense. The FERC should only be able to issue such an order if there was a positive finding that the interconnect will enhance competition and not impair the pipeline's ability to render service to its downstream customers.

Section 202 -- NEPA Compliance

Brooklyn Union supports the concept of having the Federal Energy Regulatory Commission act as the sole agency required to conduct an environmental impact statement. The authority of the Commission, however, to charge an applicant for the documentation costs is not restrained and could result in excessive and unreasonable costs.

Senator Bingaman's amendments to S. 341 accomplish the same

but not downstream interconnection, i.e., bypass?

Yes, the language in Section 201 appears to exclude the FERC from authorizing downstream interconnections for by-pass purposes.

c. What are the technical questions raised by the manner in which section 201 is drafted? How would you resolve these questions? Please provide suggested substitute language if to do so would be helpful.

Proposed Section 7(a)(3) must be modified to specifically provide that when determining whether the interconnection impairs the pipeline's ability to render adequate service, the Commission must assess the interconnection's impact not only at the point of interconnection, but also the impact to the pipeline's existing services all the way to the city gate. In addition, proposed Section 7(a)(2) must be revised to include the same notice, protest and opportunity for hearing contained in Section 7(a)(1). Without this addition, the Commission would not be able to determine whether the interconnection has met the standards identified in proposed Section 7(a)(3).

result as the provisions of this section, but in a more direct and flexible manner. Brooklyn Union would prefer, as the Bingaman amendment allows, that applicants choose from a list of FERC-designated contractors for the preparation of environmental documents necessary to assess project, as opposed to a FERC-selected contractor.

Section 203 -- NGPA Section 311 Revisions

Brooklyn Union generally supports allowing transportation on behalf of any person as a means of enhancing the competitive market for natural gas. However, the 30-day prior notice of construction provided to a state commission is not adequate to permit a local distribution company to respond to issues of service degradation and possible increased rates. It is suggested that section 203 contain an expedited prior notice and protest procedure whereby issues of this sort can be resolved in a timely manner by the Commission. This procedure should have the following characteristics:

- Notice should include a complete description of the project and the reasonably foreseeable impact on rates and service to existing customers. There should be sufficient substance to the filing so that the recipient knows or can determine the impact.
- The class of protesters would be limited to

existing customers of the pipeline who would be impacted by the project.

- The protest must be accompanied by specific claims of harm and the evidence relied upon to support such claims.

- The protest would be due in 30 days.

- The Federal Energy Regulatory Commission must resolve protests in 60 days and would be given statutory authority to resolve protests based on the written submissions.

Section 204 -- Optional Certificate Process

Brooklyn Union supports the streamlining of the construction certificate process. However, there must be some limited opportunity by impacted third parties to raise legitimate concerns. This optional certificate process should have a notice and protest procedure as described in section 203.

We believe that the provisions in this section that allow parties requesting service after completion of construction who are unable to reach agreement with the pipeline, to petition the FERC to set rates is inconsistent with the goals elsewhere of allowing parties to negotiate rates and terms of service. It also creates two sets of customers, one with administratively set rates and one with negotiated rate. This may create inequities between the customers. This section should be deleted.

We also oppose provisions that allow a pipeline to elect to convert existing facilities or services rendered under 7(c) to this section 7(i), or basically deregulate existing regulated service. The afforded protection under section 7(b) may not be adequate where the pipeline is deregulating existing regulated facilities and service as proposed by S. 570. It is recommended that pipelines not be permitted to convert existing regulated services unless there is an agreement of all impacted parties.

Section 205 -- Nonjurisdictional Option

Brooklyn Union has the same concern with this section as it does with section 204. A notice and protest procedure of the same nature is necessary to protect third party rights.

SUBTITLE B - NATURAL GAS IMPORT/EXPORT DEREGULATION COVERAGE OF THE NATURAL GAS ACT

Brooklyn Union supports the further deregulation of this area. However, the existing current process and policies are producing acceptable results and we would oppose any changes to natural gas import/export regulation which increased the oversight responsibilities under the FERC. This would represent a step backwards. These functions are largely policy and international matters that are appropriately lodged under the Secretary of Energy.

SUBTITLE C - STRUCTURAL REFORM OF THE FEDERAL ENERGY REGULATORY COMMISSION

Brooklyn Union opposes replacing the Federal Energy Regulatory Commission with a single administrator within the Department of Energy. The Commission exercises broad regulatory powers. The commission approach to regulation provides an equitable balancing of views and opinion and a tendency to elicit a more efficient decision-making process by accommodating a wide range of interests than would be possible by a single administrator. It is interesting to note that state public utility commissions are uniformly structured as multi-member bodies.

The administrator approach may also "politicize" decision-making more than it is now. Restructuring the Federal Energy Regulatory Commission from the ground up would create uncertainty and instability in the regulatory process. The natural gas industry has experienced a great deal of regulatory change in the last decade. It would be more appropriate to foster predictability in the process at this time by reforming the regulation of the industry to enhance and expedite the process rather than deregulating it.

Further, adoption of many of the proposals for expediting FERC review should reduce or eliminate the need for such a radical step of replacing the current regulatory process. If such a proposal is to be considered, any decision should be delayed pending a review of how successful the streamlining of the FERC will be in reducing regulatory bottlenecks and delay.

The Administration should be applauded for its desire to increase the voice of natural gas in Department of Energy deliberations. We believe that such a goal can be achieved more effectively by creating an Assistant Secretary for Natural Gas.

QUESTIONS OF SENATOR TIMOTHY E. WIRTH

1. In what ways do you think the Congress could best accelerate the displacement of petroleum-derived auto and truck fuels by natural gas or other alternatives?

Federal Government and Other Fleet Vehicles

The federal government currently purchases in excess of 40,000 vehicles annually and operates a fleet of more than 200,000 vehicles. Therefore, it would be extremely helpful for Congress to include provisions in S. 341 to mandate that federal agencies accelerate the conversion of their fleets to alternative fuel vehicles. This will create a substantial market pull for the production of natural gas vehicles (NGVs) and other alternatives in the private sector as well. Furthermore, clean fuel fleet requirements in the Clean Air Act could be extended to additional regions, such as those that are moderate nonattainment areas for ozone. We believe that in this manner, the economies of scale required to reduce the price of both vehicles and refueling infrastructure can be reached.

R&D for Advanced Technology

Gasoline and diesel engines have been developed and mass produced for almost a century. The gas industry has taken significant steps to develop NGVs in just a few years. However, there is a need to further accelerate the process. While representing 24 percent of the energy used in this country, less than one-half percent of the RD&D dollars are directed to natural gas technology research. Recognizing this potential, some of the leaders in the gas industry, including The American Gas Association, The Gas Research Institute, the Institute of Gas Technology, Southern California Gas, Columbia Gas and Brooklyn Union Gas, have jointly prepared a funding request to the United States Department of Energy (USDOE). This report is attached to this document and suggests expanded funding for utilization research including $27 million for NGVs in 1992. NGVs can already meet or exceed the standards of the Clean Air Act. Advanced development can both further improve the vehicles and can increase their marketability. Congress can provide leadership in this important area.

Tax Credits for Vehicles, Equipment and Refueling Infrastructure

Natural gas has both a production and transportation infrastructure in place that can accommodate natural gas use as a vehicle fuel. The only remaining piece of the supply system that must be developed are the on-site refueling stations. In order to accelerate the construction of these stations there will be a need to provide economic incentives in the early years. An income tax credit for the development of natural gas refueling (e.g. investment credits) and the purchase of natural gas vehicles or vehicle equipment would enhance the economics until a significant market develops. H.R. 1497 has already been introduced and has provisions to address this problem. We are hopeful that a similar proposal will be introduced in the Senate shortly.

Environmental Assessment on Conventional Fuels

The natural gas industry believes that the nation would be best served by the imposition of a higher tax on gasoline and diesel fuel. Such a tax would recognize the related environmental and security costs associated with motor fuels. Clean, domestic alternative fuels should be exempt from such a tax. The revenue from such an increase could finance many transportation projects including converting government fleets, providing tax credits for refueling stations and the R&D funding requested, all of which will directly create American jobs and save money in the long run.

Maintain CAFE Benefits for Alternative Fuel Vehicles

To date, one of the strongest incentives for the big three auto makers to develop and sell natural gas vehicles has been the Corporate Average Fuel Economy (CAFE) benefits assigned to alternative fueled vehicles by the Alternative Motor Fuels Act of 1988. For example, for purposes of calculating an automaker's CAFE rating, NGVs are permitted to equate to a vehicle with a fuel economy of more than 120 miles per equivalent gallon. Any changes to the CAFE requirements need to maintain and enhance the benefits to alternative fuel vehicles.

Federal Jurisdiction Over Selling Motor Fuel

Congress could facilitate the increased utilization of natural gas as a motor fuel by either establishing or clarifying the absence of FERC jurisdiction over local distribution companies (LDCs) and others who sell natural gas for vehicular use as wholesalers or retailers. Section 10008 of S. 341 clarifies the nonfederal jurisdiction status of local distribution companies as wholesalers or retailers of vehicular natural gas (VNG). Brooklyn Union supports Section 10008 and urges its early enactment.

Continuation and Expansion of UMTA Initiative

Another federal program that has greatly helped the development of NGVs, specifically in the bus market, is the alternative fuels initiatives sponsored by the Urban Mass Transit Administration (UMTA). The American Public Transit Association reported at the end of last year that there are almost 150 natural gas buses soon to go into operation in North America, many due to the UMTA Alternative Fuels Initiative (AFI). In fact, approximately 65 percent of the alternative fuel buses on order through the AFI are to be powered by natural gas. This is more than for all other alternative fuels combined. But this is still a small fraction of the several thousand transit buses on the road. Continuation and expansion of this program will have clear short term benefits as well as long term environmental benefits. The more clean fuel buses put in operation today, the less pollution down the road, since once a diesel is purchased, it is not soon replaced.

2. **Will the development of original-equipment natural gas vehicles by major manufacturers aid the economics of selling natural gas to vehicle fleets?**

Yes, the development of OEM natural gas vehicles will aid the economics of selling natural gas to vehicle fleets. It currently costs approximately $2,000 to $3,000 to convert an existing vehicle to natural gas. However, the USDOE estimates that a mass produced OEM natural gas vehicle will only cost $800 more than a conventional vehicle, and this is before the additional costs of emissions reductions to meet the Clean Air Act are added to the gasoline vehicle. In addition, natural gas is already a less expensive fuel. Production of NGVs by original equipment manufacturers (OEM) will reduce the maintenance costs by covering NGVs in the original vehicle warranty and by making available the large service and maintenance capabilities of the OEMs. And, that is exactly what is beginning to happen. Recently, General Motors announced a $40 million program in cooperation with the Gas Research Institute to begin engineering and product development of light and medium duty trucks powered by natural gas.

3. **Can your company and others now involved in converting**

vehicle fleet fueling to natural gas handle an acceleration of the schedule of such conversions over that laid out in the Clean Air Act Amendments of 1990?

Yes, most of the companies involved in the conversion of natural gas vehicles can handle an acceleration of the schedule laid out in the Clean Air Act. In fact, some plans are already underway due to the implementation of major state initiatives, including those in California and New York. However, it is important that as the market expands, that the public's safety and monetary resources be protected, by the establishment of appropriate national standards governing the conversion of vehicles to alternative fuels as well as the licensing of repair shops.

4. **What, in your opinion, are the largest barriers to greater use of natural gas by commercial vehicles?**

The two largest technical barriers to the greater use of NGVs are (1) the lack of natural gas refueling infrastructure and (2) the limited range of conversion NGVs. For example, a typical service van can carry more than 18 gallons of gasoline. A good conversion of an existing vehicle to dedicated natural gas can only hold an equivalent of up to 15 gallons of gasoline. Although the difference does not sound great, it can be a major headache to a fleet operator. As discussed in previous questions, the solutions can be expedited by (1) offering economic incentives for LDCs, OEMs and vehicle operators and by (2) accelerating R&D programs.

Another obstacle is the need eliminate the obvious bias toward liquid fuels. Myths about the safety, convenience and performance of natural gas as well as the supposed interchangeability of alcohol and gasoline all should be addressed through a program of public education.

5. **What, in your opinion, will be necessary steps toward making the use of natural gas vehicles by individuals a viable alternative to today's gasoline and diesel powered vehicles?**

There are two basic steps to replacing gasoline and diesel fuel with natural gas. These are first and foremost, development of a refueling infrastructure and consequently the use of natural gas vehicles in large vehicle fleets. Second is the mass production and full support of natural gas vehicles by original equipment manufacturers.

U.S. DEPARTMENT OF ENERGY FISCAL YEAR 1992 FUNDING

FOR

NATURAL GAS AIR QUALITY, EFFICIENCY AND SUPPLY RESEARCH, DEVELOPMENT AND DEMONSTRATION

Recommendations Prepared by

The American Gas Association
The Gas Research Institute
The Institute of Gas Technology
Southern California Gas Company
Columbia Gas System, Inc.
Brooklyn Union Gas Company

SEPTEMBER 24, 1990

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engines. These should be supported by continuing programs that build a technology base through basic research in combustion chemistry, engineering concepts, advanced materials, components and processes.

- Transportation Fuel Alternatives and Emissions Solutions--Development of dedicated natural gas vehicles initially concentrating on fleet use will contribute to the substantial reduction in mobile source emissions that will be required to meet future Clean Air Act standards and help decrease the country's dependence on foreign oil. Natural gas is much cleaner than conventional fuels but focused RD&D is needed to design vehicles for optimal performance, to demonstrate such vehicles in a variety of applications, and to develop natural gas storage and refueling technologies. As this RD&D effort progresses, further improvements in natural gas engine efficiencies will further reduce critical pollutants.

- Electrochemical Energy Conversion--Fuel cells produce electricity with only a fraction of the atmospheric pollution and at considerably higher efficiency than combustion-based power plants. This program seeks technology transfer assistance for first generation fuel cell development and accelerated research for second and third generation fuel cells aimed at introduction in 1995 and 2000, respectively. These advanced fuel cell technologies will provide even greater efficiency improvements, and can be deployed on-site in various sizes as modular, highly efficient and virtually non-polluting power plants. Another concept, the solid polymer fuel cell, promises to be a compact and highly efficient device. With accelerated RD&D, it could be introduced after the year 2000 as a vehicular powerplant with virtually no emissions.

- Gas Supply Enhancement--To maintain a supply capable of meeting future demand at competitive prices, the on-going development of tools and techniques to help ensure the economical recovery of a larger percentage of the total domestic gas resource base must continue. RD&D must thus pursue gas extraction and recovery technologies that offer the potential for large increases in domestic gas supply. This should be complemented with continuing research that seeks to develop techniques for extracting higher quality gas from biomass.

This initiative by the natural gas industry contributes toward greater energy security, improved air quality and energy efficiency which are essential to a strong U.S. economy and competitive edge. The recent events in the Middle East underscore the need to seek better utilization of our nation's indigenous resources. This recommendation for a total amount of $215 million for gas utilization and supply RD&D in Fiscal Year 1992 is required because of the increasing urgency to promote low pollution end-use technologies and fuel efficiency. This in turn will help meet more ambitious national objectives that will take us into the 21st century.

U.S. DEPARTMENT OF ENERGY
FISCAL YEAR 1992 FUNDING
FOR
NATURAL GAS AIR QUALITY, EFFICIENCY AND SUPPLY
RESEARCH, DEVELOPMENT AND DEMONSTRATION

EXECUTIVE SUMMARY

As an abundant domestic resource, natural gas can play a significant role in the United States' energy balance and has the potential to make a meaningful contribution in cleaning up the environment. Natural gas is our nation's cleanest burning fossil fuel--its combustion emits virtually no particulates or sulfur oxides, and it produces far lower emissions of ozone precursors, carbon monoxide, and other pollutants per unit of energy than coal or oil.

Intensified research, development and demonstration (RD&D) programs focused on gas utilization technologies appropriately backed by continuing gas supply RD&D must be undertaken in order to derive the above benefits. ***The gas industry recommends that the U.S. Department of Energy (DOE) undertake a long-term (10-year) natural gas RD&D program funded at $2.5 billion to augment the planned industry funding. To initiate this program, we recommend that DOE provide $215 million in Fiscal Year 1992 for natural gas RD&D. As shown in Attachment A, these funds must be allocated as follows:***

- ***$165 million for natural gas utilization programs to accelerate the availability of new technologies and reap the associated environmental, energy security and conservation benefits. The gas industry and gas equipment manufacturers will fund a projected $195 million planned for RD&D in FY'92.***

- ***$50 million to support a continuing natural gas supply RD&D program. This will supplement gas industry and producer efforts with estimated funds of $214 million in FY'92.***

Further advances in reducing combustion emissions--even from clean-burning natural gas--are required to enable a large number of areas to meet federal clean air standards and to comply with state implementation plans as their local economies and resultant emissions grow. The DOE should thus prioritize its funding initiatives starting in Fiscal Year 1992 by providing for programs on:

- Stationary Emissions and Efficiency Solutions--Research into improved, highly efficient processes and equipment should lead to reduced emissions from stationary sources such as industrial boilers, furnaces and dryers, and commercial and residential space conditioners and water heaters. Programs should focus on using natural gas for emissions control, as in cofiring and reburn for both coal and municipal solid waste systems as well as advanced combustion systems including fiber and catalytic burners. Programs should also focus on energy conversion efficiency, as in advanced heat

INTRODUCTION

The U.S. natural gas industry serves over 175 million natural gas consumers throughout the nation. In support of Federal efforts toward formulating a national energy strategy and a stronger environmental policy, the American Gas Association (A.G.A), the Gas Research Institute (GRI), and the Institute of Gas Technology (IGT) have joined some of the nation's major gas utilities to submit this proposal to DOE for an intensified research, development and demonstration (RD&D) program for natural gas utilization technologies seeking higher fuel efficiency and very low emissions. This program will benefit the nation by developing technical solutions to the air quality challenges many areas face. Backed by appropriate gas supply RD&D, it will promote greater energy security for the nation through the utilization of clean, domestic energy resources.

In 1989, the A.G.A, a national trade association comprised of some 250 natural gas distribution and transmission companies, submitted comments to the Department of Energy (DOE) discussing the goals of the national energy strategy and how, by refocusing DOE's energy research agenda, natural gas could make a greater contribution to the nation's energy security and environmental goals[1]. With air pollution contributing to various human health hazards, acid rain, ozone depletion and climate change, the issue of air quality has emerged as a strong environmental concern. Confident that natural gas can be part of the solution to the air pollution and energy security problems our nation faces, the nation's largest natural gas distribution utilities, also submitted testimony to DOE[2]. It recommended that federally sponsored increased natural gas utilization RD&D be made an essential component of the national energy strategy.

In April 1990, DOE issued its Interim Report[3] on the National Energy Strategy. This report contained a compilation of public comments which identified **increased energy efficiency as the "loudest single message"** conveyed by over 1,000 written submittals in response to the government's request for input. According to the report, "energy efficiency was seen as a way to reduce pollution, reduce dependence on foreign oil, and reduce the costs of energy". The Interim Report also noted that nationally, more than $30 billion is being spent yearly on emission controls and improved technologies to reduce emissions. Such efforts have been successful in reducing emissions since 1970, especially in urban areas. However, continuing growth is also causing many areas of the country to fall short of achieving and maintaining the National Ambient Air Quality Standards (NAAQS).

Sharing the view that natural gas is an essential component to an effective energy policy, the natural gas industry developed strategies and assessed resource needs to make this fuel a key element in enhancing our nation's future energy security and environmental quality. Focusing on efficiency and emissions-related RD&D of gas equipment and processes, and on the gas supply/demand outlook, the gas industry identified funding levels necessary to contribute to a sound national energy strategy while helping to attain environmental goals. It rapidly became evident that, given the scope of natural gas technology development, the current natural gas contribution to the national energy economy, and the heightened concern with the environment, **the Federal government should give natural gas-related RD&D a larger and much higher priority in DOE's policy initiatives and yearly budget.**

The focus of DOE's research and development activities historically has been on coal and nuclear energy; in contrast, natural gas RD&D has received only minimal support from DOE and is, by necessity, cost-shared by private companies. For example in 1992, the gas industry and equipment manufacturers plan on spending over $195 million for gas utilization RD&D and at least $215 million for gas supply RD&D. These expenditure forecasts are more than 5 times greater than the FY 1991 DOE budget request for RD&D in these two areas.

At the same time, the past efforts of these participants have repeatedly demonstrated the value of investing in gas-related RD&D. These efforts have led to progress in end-use technologies such as low-NOx combustion systems, cofiring, fuel cells, gas heat pumps, gas absorption chillers, and natural gas vehicles, and in supply research such as tight formations and coalbed methane.

Further, the regulated gas industry also supports organizations that promote specific technologies. GRI is the natural gas industry's cooperative research and development organization with membership from the pipeline, local distribution company and producer segments of the industry. GRI plans, manages and raises funding for a comprehensive program in natural gas supply, distribution and utilization. Through GRI, together with co-funding by gas utilities, the gas industry already matches the amount of DOE gas RD&D funding. The American Gas Cooling Center, the Natural Gas Vehicle (NGV) Coalition and NGAGE (Natural Gas Alliance for the Generation of Electricity) devote their efforts to commercialization of specific types of gas equipment and applications. The AGA Laboratories also successfully perform R&D that has direct application to appliance and equipment innovations. IGT has established a Sustaining Membership Program in which over 50 gas companies support mid-term research directed toward a wide variety of projects, primarily in gas utilization.

However, relative to attaining environmental goals and improving U.S. energy security, these industry-funded RD&D programs are limited by available funds. Inevitably, projects with greater benefits for gas users and realistic chances of early commercialization are pursued while more far-reaching projects that have a potentially high impact on society cannot be funded. If natural gas is to take the proper place in the nation's energy strategy, sustained accelerated RD&D is needed in these projects to increase end-use efficiency, and to lower emissions, supported by continuing research to increase energy supplies. Federal funding is the key to such accelerated research and development.

In addition to the development of new gas technologies, demonstrations and other technology transfer activities are necessary to ensure that the money spent in the research is not wasted. The gas industry has developed a solid record of success in transferring technologies to commercial use. We have worked with numerous manufacturing/commercialization partners to address the long list of issues to be overcome before successful transfer can take place. Yet many promising candidates remain, requiring further support to move from the laboratory to the marketplace.

Federally assisted technology transfer activities described in more detail in the section on specific RD&D funding recommendations will help more effectively translate the results of RD&D into widely accepted products, equipment, and processes. As pointed out in the DOE Interim Report, this can only be accomplished by building stronger partnerships between the public and private sectors.

THE IMPORTANCE OF GAS-RELATED RD&D

The United States needs an adequate DOE-funded natural gas research, development and demonstration program to meet future energy needs, reduce national security risks, and to help achieve ambient air quality standards in many areas of this country as well as to enable U.S. industry to remain competitive in today's world economy.

Natural gas can fill this important role because its attributes make it the most desirable fuel in a myriad of applications. Natural gas is the cleanest of all fossil fuels. Gas can be used as a substitute fuel for other fossil fuels to strengthen air pollution control, to reduce sulfur (SO_2) and nitrogen oxide (NO_x) emissions, as well as to control carbon monoxide and carbon dioxide emissions of other fossil fuels. Natural gas can also be used as a transportation fuel and thus help reduce the major source of air pollution in most urban areas. No other single fossil fuel is comparable to natural gas in producing environmental benefits across multiple applications.

The million-mile transmission and distribution pipeline network of the natural gas industry provides a safe and growing infrastructure to deliver environmental improvements to every region of the country. Further, natural gas can be converted into usable energy more efficiently and inexpensively than most other fuels.

Pending clean air legislation provides further incentives for DOE to increase its funding for development of natural gas utilization technologies. The combustion of fossil fuels, the central component of our nation's energy mix, will continue to power our economy for the foreseeable future. To meet federal and state clean air standards, **significant advances in reducing emissions from combustion must be achieved.**

Such significant advances can be made while also improving energy efficiency. For example, further research on electrochemical processes and thermodynamics could improve the process for transforming gas into usable energy, with even greater efficiency and essentially no adverse environmental impact. DOE can and must play a major role in gas technology development. Focused research in strategic areas will allow for the more efficient use of an abundant domestic resource, and thereby reduce our nation's reliance on foreign oil. It will also facilitate economic growth by enabling U.S. industry to compete in the global marketplace more effectively, while reducing pollution and using our own resources.

The gas industry recommends that DOE move rapidly to accelerate the development of natural gas technologies. We urge DOE to join the gas industry in sponsoring a 10-year RD&D program to significantly increase the efficiency and environmental benefits of gas use. This joint effort should begin in FY 1992 with DOE funding $215 million for natural gas RD&D, and the gas industry funding over $400 million.

This program is fully consistent with three of the major goals identified by DOE Secretary James D. Watkins in the Position Statement and Budget Overview for FY 1991[4]. **Respecting the environment, increasing energy efficiency and fortifying foundations** are DOE goals that can significantly benefit from increased natural gas utilization technology development. Such technology development must also be fully supported by a continuing strong gas supply research and development program to help fulfill a fourth major DOE goal, namely to **secure future energy supplies.**

Both gas utilization and gas supply RD&D programs are described in more detail in the following sections of this FY 1992 budget recommendation by the gas industry. While the **Gas Utilization** section describes the recommended areas of intensified and focused RD&D in fossil energy and conservation, the **Gas Supply** section presents an FY 1992 proposal that is consistent with on-going DOE-sponsored research efforts. These recommendations are also fully supportive of the Gas Research Program Implementation Plan published by DOE in April 1990[5].

GAS UTILIZATION

The gas industry has always been in favor of funding levels that are consistent with sound fiscal policy. As shown in Attachment A, our recommendation of $165 million for utilization RD&D in FY 1992 will show increases above the FY 1991 gas utilization budget in fuel cells, natural gas vehicles, and low emissions combustion systems and energy efficiency-related conservation programs. Such increases are justified by the increased urgency to develop least-cost technology options for all consumers which will aid our nation in meeting the requirements of the new clean air legislation, and will help our nation enhance its energy security.

Specific Utilization RD&D Recommendations

The following are the gas industry's specific funding recommendations for gas utilization-related RD&D sponsored by DOE in FY 1992.

Stationary Emissions and Efficiency Solutions

1. Combustion System/Emission Control ($17.8 Million)

Because of the importance of this program to the nation as part of its energy strategy and in response to Clean Air Act legislation ultimately adopted, $17.8 million is needed to accelerate and focus combustion and burner RD&D efforts aimed at developing low emissions gas equipment for residential, commercial, industrial, and utility applications. This includes high-efficiency, low-emissions burners, burner systems, and new methods of post-combustion control for new as well as retrofit installations.

The DOE Interim Report identified the end-uses that are the biggest contributors to ozone precursor and acid deposition emissions[6]. These were electric power generation, industrial processes, and the transportation sector. The first two sectors typically have large capital investments in fixed facilities. Imposition of additional air quality regulations and controls preferentially results in retrofits and/or additions of equipment in such facilities rather than new projects built from the ground up.

In the absence of low emissions burner systems, post-combustion control methods are often used for emissions control as an interim measure for compliance with new regulations. For large installations, state-of-the-art post-combustion controls such as selective catalytic reduction (SCR) systems are very costly to install and to maintain.

Allocating $6.0 million for the development of new methods of post-combustion emissions control will promote the search for practical, low-cost solutions to typical retrofit/add-on needs of electric generation and industrial process facilities. With such funding matched on an equivalent basis by the gas industry, advanced post-combustion controls for burner systems would be available for interim or retrofit applications in 2 to 4 years. If sustained over several years, such levels of funding would also permit the development of application-specific post-combustion systems as the last step in emissions reduction in a given installation. Such systems would be optimized and integrated with the combustion process stream to derive required emissions reductions without compromising process efficiency.

The gas industry recommendation also includes an expenditure of $5.3 million for co-funding accelerated research specifically focused on utility electric generation (UEG) and enhanced oil recovery (EOR) operations using natural gas combustion equipment. This has arisen from a need in the non-attainment areas of the U.S. where the switching from coal or oil to clean natural gas combustion has already occurred in an effort to control air pollution. These areas are also the ones experiencing the most rapid population and economic growth. Further, they are faced with more stringent control measures in order to attain and maintain the National Ambient Air Quality Standards (NAAQS) and other potential provisions of the proposed Clean Air Act.

The recommended research will require development and demonstration of advanced burner concepts in the very large burner sizes that are typical of UEG and EOR boilers and fluid heaters. Concepts involving increased mixing, fuel and air staging, steam injection, and enhanced heat transfer have been proven effective both in increasing efficiency and in lowering emissions of small and medium size burner applications. A similar development effort is now needed for large (over 50 million Btu per hour) burner system applications to make such applications widely used in 5 to 10 years.

In the residential/commercial end-use sector, combustion R&D efforts in energy efficiency and equipment emissions must focus on developing reliable, durable, and inexpensive materials, burner systems, and controls. A funding of $6.5 million is needed for this effort which is designed to advance the technology of low emissions residential and commercial gas combustion equipment for market entry in 3 to 7 years.

Between supply and point of end-use, natural gas is the most efficient fossil resource used in many of these applications. Furthermore, the direct combustion of natural gas in residential and commercial equipment can produce substantially lower overall volumes of air emissions than the use of equipment supplied from conventional coal-fired electric power plants. However, if gas is to continue to be a viable end-use energy choice, lower emissions from gas combustion will be required in the near future, especially for appliances and equipment used in areas which have trouble meeting the NAAQS.

2. Industrial Processes ($18.8 million)

Industrial energy consumption represents approximately 36% or 29 quadrillion Btu (quads) of the total energy consumed in the U.S. in 1988. Natural gas is most heavily utilized in the industrial sector, representing more than 40% of the 18.6 quads of gas consumed in the U.S. in 1988[7].

Based on the prominence of natural gas in industrial process applications and its preference by users, an RD&D effort by DOE to improve natural gas-fired equipment and processes is warranted. This effort must address: (1) improvements in efficiency, productivity and product quality of natural-gas-fired systems in order to maintain the competitiveness of U.S. industry in today's global economy and (2) development and evaluation of low emissions natural gas combustion equipment to meet existing and pending environmental regulations.

DOE funding of $7.8 million is recommended to demonstrate newly developed processes in real-world industrial environments, not laboratories. Several innovative concepts which promise to revolutionize the manner in which process heat is generated in the industrial sector are under development and will be available for technology transfer within the next two years. DOE funding will ensure that these environmentally sound and energy-efficient technologies contribute to the competitiveness of the American manufacturing sector in the world marketplace.

Applied RD&D efforts, funded at $4.0 million by DOE are also proposed to improve efficiency, productivity and product quality in industrial gas-fired equipment and processes through the application of advanced combustion, heat transfer and controls technology. Implementation of advanced technologies in industrial processes will provide important consumer benefits, including: (1) reduction of manufacturing costs through increased efficiency, productivity, and reduced storage, handling and preparation costs; (2) enhancement of industry's ability to expand operations and still comply with environmental regulations on combustion and process emissions; (3) stable gas send-outs and seasonal load balancing, which can help gas utilities control operating costs and pass on the savings to the consumers; (4) reduction in dependence on imported petroleum products; and (5) enhanced ability of U.S. manufacturing to compete in global markets.

The gas industry is also recommending that $6.0 million be allocated to address research and development focused on low emissions of natural gas combustion equipment for this sector. These funds will cover activities to help extend application of technologies employed in the UEG/EOR end-use sectors to industrial processes and to obtain fundamental understanding on the formation and recombination of pollutants. Such research would include second generation surface combustor concepts for process and thermal fluid heaters, improved glass tank furnaces using oxygen and natural gas cracking/oscillating burners, and industrial melters for scrap metal, mineral wool, and fiberglass production. This same technology can also be applied to ash vitrification, thus reducing potential waste disposal costs for a number of industrial processes.

Also, flue gas treatment technologies are not currently applied to industrial processes because they operate under conditions which are incompatible with temperatures and gas compositions encountered in most industrial operations. The investigation of methods to modify their range of operation, as well as the development of the above alternative emissions control technologies, will allow the cross-section of the American industrial complex that is currently most vulnerable to foreign competition to maintain its leadership while minimizing environmental degradation.

Substantial advances in energy technologies hinge on research and development of ceramics and other advanced materials. The advantages of structural ceramic materials versus metal alloys are well documented. Ceramics are ideal because they are lightweight, retain their strength at high temperatures, and have high corrosion and wear resistance.

However, continuing RD&D is needed to address several technical issues that have impeded wide market penetration. A funding level of $1 million is recommended for research to develop more systematic fabrication techniques for the forming and sintering of more reliable ceramic parts. Moreover, reproducible and cost-effective manufacturing and quality control techniques are needed for the large-scale production of reliable and inexpensive ceramic materials and components for a wide variety of high-temperature uses.

3. Natural Gas Cooling ($18.0 Million)

By extracting heat from the outside air and transferring it to the indoor space, gas heat pumps can actually supply more thermal energy than is contained in the input fuel. The gas heat pump's cooling effect is accomplished by reversing this process. The gas heat pump thus provides heating and cooling in a single unit.

Current performance estimates suggest that in heating, the gas heat pump could save one-half of the gas used in a conventional furnace and one-quarter of the gas used in a high efficiency furnace[8]. Furthermore, these devices offer the potential for lower resource energy consumption than systems powered by electricity produced from fossil fuels or nuclear energy. The gas heat pump is attractive because it can provide cost-effective cooling in most warm regions where electric prices and demand charges are structured to discourage load growth. In addition, use of gas heat pumps could help to level cyclic gas and electric demand profiles, favorably affecting utility operating expenses and the cost of energy to the consumer.

DOE-sponsored research co-funded by the gas industry is necessary to put these advantages to work through reliable and cost-effective gas heat pumps for residential and commercial applications. To improve their performance, reliability, maintenance and endurance, such research must include the evaluation of promising technical approaches, fundamental research in basic heat pump concepts, processes, phenomena, advanced working fluids and materials, along with research on generic component development. These activities must be integrated into overall gas heat pump system development and analysis.

Presently, research is being pursued at a slow pace because of the modest funding levels. Further improvements involve the use of non-azeotropic refrigerant mixtures in engine-driven systems with the potential for eliminating backup boilers or resistance heaters and offering high performance during both winter and summer operation.

To help accelerate technology transfer, it is also proposed that DOE sponsor technology transfer of heat pumps for residential and commercial applications, following gas industry field testing of these devices. In addition, DOE emphasis on engine emissions reduction would contribute significantly to engine-driven gas heat pump success.

DOE should also fund development of advanced absorption systems for large commercial chiller applications. Requiring no chlorofluorocarbon (CFC/HCFC) refrigerants, these systems can be a major contributor to both gas and electric utility integrated resource planning programs to yield significant energy savings if used on a widespread basis.

Desiccant materials have also been applied in cooling cycles, paralleling the performance of conventional residential and commercial electric cooling equipment. Further, desiccant cooling cycles also do not require the CFC/HCFC refrigerants in use with existing electric vapor compression systems. Desiccant cooling cycles introduce 100% fresh air to the conditioned space. This is an air quality health benefit because it helps dilute contaminants such as radon and tobacco smoke. Desiccant cooling cycles also have the inherent ability to control temperature and humidity independently. Such control of humidity can help avoid indoor air health hazards such as the growth of airborne bacteria and fungi.

Recommendations for DOE-sponsored research include development of liquid desiccants, solid desiccant composite materials, solid desiccants formulated into structural load-bearing shapes, and the engineering of desiccant performance. These avenues of technology development would complement and strengthen the current gas industry RD&D program and contribute to the competitiveness of this technology for environmentally sound, energy-efficient residential and commercial cooling.

4. Heat Engines ($6.9 Million)

Gas-fired heat engines can contribute positively to the environment and energy conservation. Therefore, the gas industry recommends intensified research and development under DOE's Heat Engine Program for the development of high efficiency natural gas-powered turbines in a wide array of sizes for electric generation. Such a program should include advanced combined cycle gas turbines, steam-injected gas turbines (STIG), intercooled steam-injected gas turbines (ISTIG) and chemically recuperated reheat gas turbines (IR-CRGT), as well as low emissions gas turbine retrofit equipment that helps avoid the costly alternative of post-combustion emission control.

The ISTIGs, in particular, are approximately fifty percent more efficient than conventional powerplants*9*, cost half as much as new coal or nuclear plants and can help solve the nation's air pollution problems. Conceptual studies of the IR-CRGT turbine indicate that high efficiencies and very low emissions can be achieved using this technology *10* In this technology, some of the natural gas fuel is reformed using heat from the turbine exhaust, thus increasing system efficiency to levels as high as 60%. The presence of hydrogen in the fuel can decrease NO_x to below 5 ppm. The principal area for research is the development of an efficient reformer that operates at temperatures low enough for effective heat recovery from the turbine exhaust.

The need also exists for RD&D efforts aimed at other engines. Such efforts must adapt the latest liquid-fueled engine technology to dedicated natural gas engines that produce shaft power for water pumping, gas compression and various industrial and commercial applications*11*. This includes increasing efficiency and power output through improved combustion techniques, and reducing emissions while preserving performance through advanced controls, optimized components, and innovative exhaust treatment techniques.

5. Coal and Waste Cofiring/Reburn ($8.5 Million)

Basic cofiring of coal with natural gas involves the injection of gas into the boiler to provide a fraction of its total heat input. In recent full-scale tests this technique has reduced the amount of SO_2 emissions in a greater proportion than the amount of gas used in the boiler*12*. Further, testing has indicated that cofiring can also be effective in reducing stack opacity. Other potential benefits to be documented are start-up improvement, operating and maintenance cost reductions, peak capacity and availability improvements, turn-down capability increases, and boiler slagging/fouling control.

Reburn technology is aimed primarily at reducing power plant NOx emissions. Using gas as a small portion of the boiler fuel, reburn technology involves injecting that fuel into a zone beyond the primary combustion zone to create a natural gas-rich "reburn" zone.

Pilot scale tests indicate gas reburning in cyclone boilers could potentially reduce NO_x emissions by more than 60 percent *13*. This is particularly significant as no other validated NO_x reduction technique exists for these boilers. Although the majority of cyclone units are over 20 years of age, utilities plan to operate many of these units for at least an additional 10 to 20 years. In addition, the majority of these units are in the Midwest, an area targeted for acid rain and ozone emissions control.

Gas reburn combined with dry sorbent injection (GR-SI) refers to combining reburn techniques with the injection of dry calcium-based sorbent to reduce both NO_x and SO_2 emissions. Combining gas reburn with sorbent injection is intended to reduce the cost and complexity of straight sorbent injection technology by reducing the amount of sorbent required for equivalent SO_2 reduction. This decreases the additional particulate burden on the plant's electrostatic precipitator. GR-SI is considered applicable to all boiler designs, is retrofitted more easily than scrubber technology, and may offer some site-specific operational enhancements.

The gas industry applauds the efforts of DOE in supporting the development of cofiring technologies as part of its Clean Coal Technology Program. The gas industry encourages DOE to continue its program to support further advances of cofiring technologies such as NOXSO, a dry regenerative sorbent process, and the Parsons catalytic reduction process to reduce NO_x and SO_2 by levels greater than 90%.

While utility applications are supported by the DOE's Clean Coal Technology Program, cofiring technology applications to industrial processes and waste-to-energy plants are not addressed. Developments in these areas are at the early stages, but will require significant funding to support technology advancements.

Potentially more stringent emission limits coupled with increased enforcement are expected for existing industrial boilers burning solid and liquid fuels or wastes. Gas cofiring offers emission reductions plus related operational enhancements such as improved load-following and greater fuel flexibility. Research is needed to develop gas burner system designs and guidelines for site-specific retrofit applications. Testing is needed to compare baseline system and cofiring technology performance and economics relative to competing approaches.

The combustion of municipal waste is expected to continue to increase in the 1990's both as a solid waste management option and as an energy source. New emission regulations are placing greater demands on new and existing municipal waste combustion sources. Natural-gas-based technologies can provide cost-effective emissions control options for two different applications. First, combustion improvements in existing municipal waste combustors (MWC) using basic cofiring of natural gas can result in reduced emissions of toxic organic species, such as polychlorinated dibenzo dioxins and furans. Pilot tests have shown that combustion conditions significantly affect trace organic emissions, and that natural gas cofiring can reduce such emissions. Combustion modifications based on natural gas cofiring can be a very cost-effective retrofit alternative to add-on controls for existing MWC plants.

At GRI, RD&D efforts have focused on cofiring natural gas and refuse-derived fuel (RDF). A field evaluation of RDF-gas cofiring is planned for early 1991. Further research is needed to develop and optimize this technique for other MWC configurations such as modular units and the mass burn moving grate, and then to demonstrate these technologies at full scale. Such full-scale demonstration must be proven if these alternatives are to be recognized as viable by users and regulators.

The second potential MWC application is the use of natural gas reburn for NO_x control. Pilot studies and tests have shown up to 60% NO_x reduction in MWC. This technology is ready for transfer to operational municipal solid waste incinerators. Gas industry co-funding is available but further RD&D funding from DOE is needed to optimize the process for various MWC equipment configurations (such as modular and RDF stokers), to investigate and develop advanced reburn concepts, and to demonstrate the cost-effectiveness of these NO_x control techniques at full scale so that technology transfer can occur in the next 5 years.

6. Advanced Research & Technology Development (ARTD) ($6.0 Million)

The Advanced Research and Technology Development program generally supports basic research in combustion chemistry, engineering concepts, advanced process development, and materials and components that provide a technology base for ongoing fossil energy projects. Current research needs include: development of advanced high-temperature materials capable of resisting chemical attack from sodium and chlorine for application in glass and aluminum melting; development of inexpensive and durable catalysts to bring natural gas catalytic combustion closer to practical implementation; improving the understanding of the interaction of gasification catalysts with carbon/steam and carbon/hydrogen reactions; developing advanced processes for low-cost synthesized gas; developing lower-cost acid-gas cleanup processes; continuation of efforts to assess advanced cleanup technology for alkali metals, particulates and tars; and biological and catalytic production of high-value chemicals.

Transportation Fuel Alternatives and Emissions Solutions

1. Natural Gas Vehicles (NGVs) ($27.0 Million)

Development and utilization of vehicles powered by compressed natural gas would serve the national interest by helping to reduce reliance on less secure liquid fuels for transportation and by improving air quality. Natural gas is an abundant domestic fuel resource. It is also one of the cleanest fuels in its native form, requiring 15% less energy than gasoline for extraction and refining and 50% less energy than methanol manufactured from natural gas.

The emissions from natural gas vehicles (NGVs) have shown significant reductions in reactive hydrocarbons, carbon monoxide, and NO_x produced by gasoline-powered vehicles. Furthermore, unlike gasoline or diesel-powered vehicles, NGVs emit almost no sulfur oxides or particulate matter. Fleet use of NGVs in congested cities would provide a significant benefit to those areas where air quality improvement is most critical. There were over 59 such cities identified in the DOE Interim Report[14].

Moreover, the technology-forcing EPA particulate emissions standards effective in 1991 justify accelerated and focused development of advanced, dedicated natural gas-powered engines if heavy duty diesel engine users are to have a "clean" fuel vehicle alternative. The final Clean Air Act amendments will probably contain vehicle tailpipe emissions control requirements that mandate a 60 percent reduction in NO_x and 40 percent reduction in hydrocarbons by 1993. These amendments will most likely provide for further reductions after 2004 if EPA determines the air quality is in need of further improvement. Furthermore, within 5 to 7 years, fleet vehicles must use clean fuels.

Congress recognized the need for developing natural gas-powered heavy duty trucks and buses when it passed the Alternative Motor Fuels Act of 1988, which authorized $6 million for the development and demonstration of alternative-fueled trucks and buses. It also made available through the Department of Transportation's Urban Mass Transit Administration funding for the purchase by local mass transit authorities of alternative fuel buses that can meet the EPA 1991 emission standards.

As a direct result of research sponsored by the gas industry, heavy duty engines dedicated to natural gas use are becoming a reality mainly through the conversion of heavy duty vehicular diesel engine designs. Fundamental research is also being carried out on gasoline as well as diesel-derivative engines in a variety of sizes to acquire a thorough understanding of the intricacies of gaseous fuel injection, carburetion, manifolding, combustion, power optimization and emissions control so that natural gas can become broadly accepted as a transportation fuel.

Further accelerated research into novel gas compression concepts is required to advance the development of compressor technology that will facilitate the growth of the necessary natural gas refueling network. Research must also be conducted on advanced storage systems, such as sorbent materials, to increase the understanding of gas storage technology, particularly the fundamental principles of natural gas adsorption, absorption, clathration and catalysis. DOE funding of $10 million is recommended to cover these activities which will also be co-funded by the gas industry.

In addition, $15 million in DOE funding is also needed to conduct accelerated technology transfer on a variety of NGVs in many medium and heavy duty applications. To be most effective, such technology transfer activity requires that the government purchase and operate NGVs for its fleet. In addition, involvement of the major original equipment manufacturers (OEMs) is essential to the market success of natural gas vehicles. Such involvement is beginning to take place through co-funding with various utilities and GRI, and will contribute in FY 1992 the additional resources needed well in excess of the $15 million in DOE funds recommended here. This will provide the further impetus for RD&D activities leading to the widespread use of natural gas fleet vehicles in this country during the next 3 to 5 years.

Advanced propulsion concepts fueled by natural gas must also evolve as a partial solution to air emissions from the transportation sector. Low cost versions of aerospace-derivative fuel cells need to be developed for vehicular use. A promising concept is the use of solid polymer fuel cells to generate on-board power for propulsion. With initial DOE funding of $2 million, this research could lead to major improvements in power density over the phosphoric acid unit presently being tried in the fuel cell/battery bus program, partly sponsored by DOE.

Electrochemical Energy Conversion

1. Fuel Cells ($62.0 Million)

Natural gas-powered fuel cells convert the energy content of gas directly into electricity and by-product heat using a highly efficient electrochemical process. The electrical conversion efficiency of gas-powered fuel cells is approximately 15-20 percentage points greater than the conversion efficiency of traditional electrical generation[15]. For example, using molten carbonate fuel cells in power generation applications could achieve electrical efficiencies of 55 percent[16] compared to conversion efficiencies of 33 percent by conventional coal or gas-burning central station electric powerplants[17]. But more important is the fact that fuel cells are also environmentally benign, generating very little noise and vibration, and emitting virtually no pollutants.

Through DOE research assistance, this technology appears to be on the verge of becoming an important element in future energy conversion applications. Recently, a U.S. and a Japanese company have committed approximately $70 million to begin commercial production and marketing of 200 KW first generation (phosphoric acid) fuel cell powerplants.

To date, the gas and electric industries and DOE have jointly invested over $200 million in research and development of the phosphoric acid fuel cell system. To ensure this sizable investment brings the appropriate economic returns and environmental benefits, a vigorous national technology transfer program must follow. A continuing strong partnership between DOE and the industry is essential to such a program, to both provide the impetus for widespread initial deployment of fuel cells throughout this country, and to build a technology database for the next generation units.

The gas industry proposes that DOE operate a technology transfer program similar to the Alternative Motor Fuels Initiative. Under the proposed program, the federal government would draw upon a $9 million pool to offset the incremental cost to buy fuel cells over the $1,000/KW cost of conventional cogeneration packages. In this manner, both private and governmental entities would be aided in purchasing and testing units which, because of their incremental effect on the total number of orders, would be available at more competitive prices than would otherwise be possible.

RD&D funding is also required for the development of advanced fuel cells, which will operate at higher temperatures, allowing them to achieve even higher efficiencies and make them suitable for industrial applications. These second and third generation fuel cell concepts are still 5 and 10 years away from commercial use respectively, and therefore, are critically dependent upon continuity of federal RD&D support to supplement industry efforts.

Molten carbonate fuel cells (MCFC), which can achieve an overall electrical conversion efficiency of 55%, are targeted for introduction in the 250 KW size in 1995. A cost goal of $1,000/KW could be achieved if sufficient RD&D funding is obtained. Solid oxide fuel cells (SOFC), which operate at higher temperature and higher current densities than MCFC, can provide compact and highly efficient small power plants. However, because of its higher operating temperature, SOFC introduction requires considerable materials development, and therefore lags behind MCFC by about 5 years.

Because of the importance of these technologies, a total of $38.5 million should be used to support accelerated RD&D of MCFC, and $10.5 million should be used for accelerated and focused development of SOFC technologies. Furthermore, $2.0 million should be allocated for intensified development of solid polymer (proton exchange membrane) fuel cell technology. This is a promising new approach to the development of fast-response, compact fuel cells with low temperature heat rejection, suitable for electric power generation in stationary as well as mobile use. An additional $2.0 million should also be allocated to applied fuel cell research covering projects aimed at using solid polymer cell concepts in small-scale electric power generation, and projects that seek to improve the reliability and life of critical fuel cell components.

GAS SUPPLY

DOE's continuing involvement in gas supply research is essential to ensure the recovery of a larger percentage of the total domestic gas resource base. Our recommendation of $49.9 million for FY 1992 RD&D shows no increase above the industry's recommended FY 1991 funding levels and is predicated on the continuation of the gas supply research programs recommended for FY 1991.

Estimated consumption of natural gas in 1989 was 19.4 quads. Current domestic production is running at about 17.6 quads annually with the balance of demand met by other sources such as, storage, supplemental gaseous fuels and natural gas imports. The critical question is whether the capability exists for additional domestic production at competitive prices to meet projected increased demand.

A recent Department of Energy study *18* shows that a technically recoverable resource base of 1,059 trillion cubic feet (Tcf) of natural gas exists in the lower-48 states. At the 1989 level of nationwide gas consumption, this amount is approximately equivalent to a 54-year supply.

The amount of gas that can be recovered from the total gas resource base is directly contingent upon the ability to develop new tools and techniques to recover this gas at commercially viable prices. This resource base is made up of reserves and resources. The recovery of gas in the "resources" category requires discovery and development of **new** technology on the basis of an improved understanding of reservoir geometry. Of the total resource evaluated in the lower-48 states 583 Tcf is judged economically recoverable at 1987 wellhead prices of less than $3/Mcf. An additional 174 Tcf of gas is judged economically recoverable in a price range of $3 to $5/Mcf.

It is clear from the above DOE study that there is no gas resource limitation that would preclude an expanded role for gas in the U.S. energy economy. The uncertainties of gas deliverability are not resource limitations. Rather, they are the pace of technological innovation and of new investment that will be necessary to sustain the levels of gas production needed in the future to meet increased demand resulting from environmental concerns. What remains to be developed are concepts for recovering conventional and unconventional gas at competitive prices.

Moreover, because of the potentially enormous size of advanced unconventional natural gas resources such as deep source gas reservoirs and secondary recovery techniques, extensive research is needed to both verify how much may be economically recoverable and to develop the requisite technology. Simply stated, early research and development efforts in the area of deep source gas, subquality gas upgrading and secondary gas recovery (such as coproduction and inert gas sweep) will help define the scope of the resource. Continuing federally sponsored research is necessary to encourage such exploration and to lower production costs, providing increased assurance that plenty of gas will continue to be available at competitive prices for several hundred years into the future.

Specific Supply RD&D Recommendations

Technology can make a difference in the cost of production of gas from the resource base. The gas resource base accessible to U.S. gas users under current industry practices generally reflects the historical perceptions since the 1970's of that resource base. Under then **current practice**, U.S. gas production was sustained primarily by the discovery of new high-permeability fields and reserve appreciation in known fields using traditional development practices. Less conventional sources, such as Devonian shale, tight sands, and coalbed methane played a very minor role in industry activity. These sources were then considered to require very high energy prices and/or new technology to ensure their viability.

In the 1980's **new initiatives** began to expand the perception of the gas resource base available to the U.S. gas user. New technologies and practices developed in the 1980's or expected in the future indicate that less conventional gas sources can play a substantial role in future gas supply, even without high prices.

A 1989 GRI Baseline Projection covering 20 years showed current practice supply declining through the projection period as old fields are depleted[19]. The increased gas supply in the projection arises from the growing role of new initiatives in the U.S. gas supply picture. For example, the incremental lower-48 gas production resulting from advanced technology is projected to provide 14 percent of U.S. gas supply by 2000 and 23 percent by 2010. The advanced technology production is from Devonian shale, tight sands, coal seams, and watered-out reservoirs.

This advanced technology production does not include any contribution from improved gas recovery from high-permeability gas reservoirs using more intensive in-field drilling or from geopressured reservoirs. A recent DOE gas resource study indicated that, with existing technology, the resource is estimated at 56 Tcf recoverable at $3/Mcf and 74 Tcf recoverable at $5/Mcf.

Coalbed methane and low-permeability production are expected to grow substantially over the 20-year projection period, with more of the growth occurring by the year 2000. Devonian shale gas production will also increase substantially after the year 2000. The growth in all these resource categories is contingent upon the availability of advanced technology.

The contribution of advanced technology production in turn will depend on the pace at which the predictability and reliability of new production techniques can be demonstrated and brought into widespread use. These advanced technologies will need to become available in the early-1990s. This can be achieved only through an expanded and directed near-term supply R&D program sponsored by DOE in cooperation with the gas industry.

It is clear that advanced gas well completion and production technology will be a major factor if the United States is to solve some of its near-term environmental problems through an expanded role for natural gas. What is needed is an aggressive federal/gas industry joint R&D effort during the next ten years. This effort should include continued research on production of natural gas from geopressured resources, and synthetic gas from biofuels and coal. As described in the following, these technologies could provide additional supplies of gas in the 2010 timeframe.

1. Unconventional Natural Gas ($23.8 Million)
Large amounts of natural gas have been identified in tight geological formations such as Devonian shales and tight sands, which have been estimated to contain more than 1,800 Tcf and 900 Tcf of natural gas, respectively *18*. Tight formation gas is produced using advanced recovery techniques such as hydraulic fracturing. A.G.A. estimates that favorable economic conditions and substantial investment in advanced recovery techniques could increase the accessible gas resources and improve the economics of gas production *20*

Basic geoscience research must be expanded to maximize the amount of natural gas recovered from our abundant resource base. This research should be aimed at increasing our knowledge of the geological, geochemical and geophysical characteristics and parameters of both conventional and unconventional formations. This cross-cutting, reservoir characterization-type research is essential to both exploration and production in new formations, which are characterized by subtle traps. It is also essential to the application of secondary recovery techniques in existing fields.

To enhance the development of technology necessary to recover the natural gas from unconventional formations, more research must also be conducted to develop stimulation techniques to fracture tight rock formations that restrict gas flow. Current fracturing techniques induce only shallow fractures of a few hundred feet. Field testing must be conducted to refine techniques for inducing deep fractures of several thousand feet and to control the direction of the fracture for optimal production results. Research information must be collected from field testing to establish a technological database for stimulation, economic modeling and other analytical purposes.

In addition, advanced drilling techniques (directional and horizontal) must be refined and improved to increase production rates and reduce drilling costs. Funding of $23.8 million in the unconventional natural gas recovery program is recommended to continue DOE's secondary gas recovery program and ongoing research activities in western tight sands, Devonian shales, and other complex formations. This funding level will also support expanded geoscience research.

2. Surface Coal Gasification ($8.5 Million)

Surface coal gasification is an important technology that can augment future natural gas supplies. Based on anticipated economics, A.G.A. projects that, by the year 2010, surface coal gasification has the potential to contribute approximately 100 billion cubic feet (Bcf) of additional gas supplies. With vigorous RD&D support, this economic threshold could be lowered. Surface coal gasification could then increase this level of production, thus enhancing the domestic gas production capability*20*.

Current technologies allow significant production of gas from coal; however, substantial research into the gasification process is necessary if gas synthesized from coal is to play a role in meeting this nation's future energy needs. Gasification techniques must be developed to accommodate high-sulfur Eastern coals and combustion-inhibiting coal "fines". Research must be conducted to develop techniques for gasifying the fines, for treatment and disposal of liquid byproducts, and for consolidating fines and tars into a useful byproduct. Further scaleup of mild gasification is also needed before this technology can be put to full use.

Scientific and engineering feasibility studies of advanced gasification processes must also be conducted to develop a technological database for such processes.

3. Geopressured Methane ($9.6 Million)

Geopressured methane is found in either a free state or dissolved in water and trapped in sedimentary rock at higher-than-normal pressures. One of the largest geopressured areas underlies a portion of the Texas and Louisiana Gulf Coast. Estimates of the total resource in-place range up to 6,000 Tcf; however, estimates of the amounts of gas that might ultimately be recovered using current recovery techniques, range between 10 and 150 Tcf*18*. If technological breakthroughs can be achieved, geopressured methane could become another major source of domestic energy.

Research currently conducted by DOE in geopressured/geothermal zones is focused on reservoir science, recovering gas and producing electricity from heat available in the reservoir brine. DOE research should concentrate on improved understanding of the scientific aspects of reservoir modeling and production dynamics and on recovering the vast amount of dissolved methane found in geopressured zones. In addition to DOE's current geopressured program, DOE should develop new approaches to maximize gas production and minimize brine production.

4. Biofuels ($8.0 Million)

Since the supply of biomass and waste materials is virtually limitless, supplemental methane supplies from biomass and waste conversions can add significantly to the total future gas supply. In addition, controlled production and use of methane from these sources can reduce natural release of methane from the decay of these waste materials. Such decay is a substantial contributor to the overall rate of methane emissions to the atmosphere. Finding sites for disposal of municipal solid waste is an increasing problem in communities across the nation. Therefore, developing energy from municipal solid waste and other biomass would promote the conservation of resources and derive environmental benefits arising from productive use of currently "useless" materials. Presently, the quality of the gas produced and the lack of suitable processing techniques inhibit the widespread use of these potential gas resources.

The gas industry fully supports the gas-related biofuels RD&D being carried out at the Solar Energy Research Institute (SERI) and recommends strong federal support for continuation of these important activities. Advances have been made in both the thermochemical and biochemical conversion processes, but more extensive studies and technology advancements are necessary to fulfill biomass' contribution as a usable source of energy.

Of particular interest to the gas industry is SERI's work in the biotechnology process of anaerobic digestion of municipal solid waste that includes genetic and other improvement of biological organisms and development of innovative reactor design concepts. Another significant area of research at SERI includes methods to remove carbon dioxide from the air or from combustion plant stacks.

Another area of interest to the gas industry is the research conducted by IGT on advanced biological and thermal gasification of municipal solid waste both in landfills and above ground reactors.

A total of $8.0 million is needed to perform these gas supply-related RD&D activities in FY 1992. Of this, $4.0 million should be dedicated to funding SERI activities. Strong, stable funding levels from DOE for all biofuels research work at SERI will help ensure successful results.

CONCLUSIONS

The natural gas industry recognizes that greater energy security, improved air quality and energy efficiency are essential to a strong U.S. economy and competitive edge. The recommendation for a total amount of $215 million for gas utilization and supply RD&D in Fiscal Year 1992 is required because of the increasing urgency to promote efficient end-use technologies and conservation measures that help meet more ambitious environmental objectives than in the past.

The gas industry recommendation requests funding only for those technologies that are essential and prudent for the orderly development of advanced and new gas utilization and supply methods and processes. With the focus of the Administration, Congress and the public on energy efficiency and clean air, there is a growing consensus that natural gas has an increasing role to play in our nation's energy security and environmental quality. To make this a reality, there must be increased focus on federal funding for research and development of technologies that utilize this gas more efficiently while minimizing emissions into the atmosphere and at the same time assuring its continued availability.

Meeting these challenges will require careful planning for energy usage in the future. That is why the gas industry is actively providing inputs into both a national energy strategy plan and the DOE yearly budget. We believe that a necessary component of this planning effort must include a re-examination of DOE funding for energy utilization technology research and development. Additional levels of funding to develop new low emission and fuel-efficient energy technologies will be necessary to satisfy pressing air quality concerns. Therefore, in developing a sound national energy strategy, DOE must provide natural gas-related R&D a much larger presence in its FY 1992 budget.

The near and long-term benefits of technology breakthroughs resulting from this research will have wide application throughout the country. The nation will not only achieve improved air quality and ensure the health and well-being of its citizens, but it will also promote the efficient use of its energy resources. In so doing, the energy security of the nation will be enhanced while enabling U.S. industry to better compete in the global marketplace as a leader in emissions reduction, new vehicle technologies and advanced energy conversion methods .

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Attachment A
DOE FY 1991 & 1992 Gas-Related Budget
Major Gas-Related Emissions/Efficiency Utilization and Supply Research Programs
($ Millions)

	FY 1990 DOE Request	FY 1990 Gas Industry Recomm	FY 1990 Congress Appropr	FY 1991 DOE Request	FY 1991 Gas Industry Recomm	FY 1992 Gas Industry Recomm
Stationary Emissions/Efficiency						
Combustion--System/Emiss. Cont.	0.0	2.0	0.0	0.0	0.5	17.8
Conservation (Cooling & Industrial Processes)	10.2	29.5	25.4	17.8	16.8	36.8
Heat Engines	0.0	8.0	0.0	0.0	2.9	6.9
Coal & Waste Cofiring/Reburn	N/A	N/A	2.5	0.0	8.5	8.5
ARTD	3.0	6.0	4.7	3.9	6.0	6.0
Transp. Fuel/Emissions Solutions						
Natural Gas Vehicles	0.7	9.5	2.5	4.0	10.6	27.0
Electrochemical Energy Conversion						
Fuel Cells	6.5	36.5	30.1	7.1	40.5	62.0
Subtotal	**20.4**	**91.5**	**65.2**	**32.8**	**85.8**	**165.0**
Gas Supply Enhancement						
Unconventional Natural Gas	4.1	15.0	14.6	13.7	23.3	23.8
Surface Coal Gasification	8.7	3.4	23.7	8.5	8.5	8.5
Geopressured Resources	2.9	8.4	6.0	2.9	9.6	9.6
Biofuels	4.5	5.0	8.6	2.5	8.0	8.0
Underground Coal Gasification	0.4	2.5	0.8	0.5	0.5	0.0
Geosciences	3.0	*	4.0	4.5	*	*
Subtotal	**23.6**	**34.3**	**57.7**	**32.6**	**49.9**	**49.9**
TOTAL	**$44.0**	**$125.8**	**$122.9**	**$65.4**	**$135.7**	**$214.9**

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* While the gas industry is supporting geosciences as a concept, it is not supporting a specific line-item funding level. The industry is, however, supporting a funding level of $10 million for gas related geoscience work that is included in other line items, e.g., Advanced Extraction and Process Technology and Unconventional Natural Gas.

UNION CARBIDE CORPORATION 39 OLD RIDGEBURY ROAD, DANBURY, CT 06817-0001

F. JOSEPH GRAHAM
DIRECTOR
ENERGY POLICY AND SUPPLY

March 25, 1991

The Honorable J. Bennett Johnston, Chairman
Committee on Energy and Natural Resources
United States Senate
136 Dirksen Senate Office Building
Washington, D.C. 20510-6150

Dear Senator Johnston:

Receipt is acknowledged of your March 11, 1991 letter.

First, allow me to thank you and the Committee again for allowing Union Carbide Corporation and the Petrochemical Energy Group to be heard.

Second, attached are the responses to the questions propounded by you at the hearing and as attached to your letter of March 11, and to the questions propounded by Senator Domenici, as attached to your letter of March 11, 1991.

We stand ready to be of any assistance that the Committee or its Members might desire.

Very truly yours,

F. Joseph Graham

F. Joseph Graham

cc: The Honorable Pete V. Domenici
United States Senate
434 Dirksen Senate Office Building
Washington, D.C. 20510

ANSWERS OF F. JOSEPH GRAHAM ON BEHALF OF UNION CARBIDE CORPORATION AND THE PETROCHEMICAL ENERGY GROUP TO SENATOR J. BENNETT JOHNSTON POST-HEARING QUESTIONS, HEARING ON TITLE X OF S. 341 THE NATIONAL ENERGY SECURITY ACT OF 1991

I. Answer to question propounded at the hearing of March 7, 1991.

First, please allow me to respond to the question propounded by you at the hearing which I asked leave to answer at a later date. Because of the extreme significance of the question, I wanted the opportunity to consult with the sponsors of my testimony before answering.

The question, as I recall, was: whether the concerns of the industrial users would be satisfied if the Act would mandate open access, as defined in the NES, on all interstate pipelines. I regret that the answer must be in the negative, for the following reasons:

(A) In my testimony of March 4, 1991, at page 24, I attempted to make the point that the two preconditions in the NES are critical, not only for industrial end users, but for all consumers. Those two preconditions were and are:

(1) the pipeline provides comparable service to third party shippers; and

(2) the pipeline (or the broker) does not have market power.

(B) The inference I drew from the question was whether the first of the above two preconditions would suffice. That is, would mandatory open access that would guarantee comparable service to third party shippers suffice to the degree that the call for an assessment of whether the pipeline also had market power could be dropped.

(C) After due consideration, I regret to say that the answer is in the negative. If one were to assume that the interstate pipelines would continue to have monopoly and monopsony power constrained by federal regulation, then the answer would be in the affirmative. However, that assumption is not a safe one in light of either S. 341 or of the National Energy Strategy Act. Some lessening, if not removal, of constraints on the exercise of monopoly and monopsony power are contemplated by the legislation. Therefore, the answer must be in the negative.

The reason can perhaps be best illustrated by reference to oil pipelines regulated by the FERC. In theory, if not in practice, these oil pipelines are supposed to be common carriers, a more extreme version of "open access" than is sought or contemplated for natural gas pipelines. If the oil pipeline is allowed to set whatever rates, terms, and conditions it wishes, the enforcement of common carriage is meaningless where the pipeline exercises market power. For example, where the oil pipeline is the only access between supply and markets, or even the dominant one, then being able to secure transportation is no solace when the pipeline can charge a monopoly rate, one so high as to preclude an economic arrangement.

This same principle holds true, even more true, with natural gas pipelines. It is even more true since the natural gas pipeline is also a merchant of gas and has every incentive to raise the rates for competitors using the pipeline for transportation so that consumers will be forced to buy from the pipeline itself.

Therefore, we remain persuaded that both pre-conditions are required in order to constrain the exercise of monopoly and monopsony power.

II. Questions propounded on March 11, 1991.

1. **To the extent necessary, please supplement your testimony with a more detailed analysis of title II of S. 570, the National Energy Strategy Act. Please address both the policy implications of title II and questions raised by the individual provisions of title II.**

Answer: Union Carbide Corporation and the Petrochemical Energy Group filed supplemental testimony on the National Energy Strategy Act on March 6, 1991. Our review to date leads us to conclude that we have nothing to add at this time.

2. **In particular, please address section 201 of S. 570, the so-called mandatory interconnect provisions.**
    a. **What are the policy issues raised in connection with this section?**
    b. **Does the section achieve its stated purpose of authorizing the FERC to order upstream interconnection but not downstream interconnection, *i.e.*, bypass?**

c. **What are the technical questions raised by the manner in which section 201 is drafted? How would you resolve these questions? Please provide suggested substitute language if to do so would be helpful.**

Answer to 2(a): This subject was briefly covered in the testimony of March 6, 1991, at page 3 and in Appendix A to that testimony at page 1. The policy issues raised are:

(A) Does new Section 7(a)(1) include "transportation" of natural gas? According to the analysis provided by the Secretary of Energy, this provision is supposed to authorize the Commission to direct an interconnection with a jurisdictional or non-jurisdictional pipeline (limited to the new 7(k) pipelines) "to direct delivery or sale to local distribution companies", said to be similar, existing authority when applied to jurisdictional pipelines. The word "delivery" is taken to mean "transportation" gas as distinguished from "sales" gas, the latter purchased from the pipeline and the former purchased from a third party.

(1) It is not clear from the wording of new Section 7(a)(1) that "transportation" gas is included. The wording may be construed to mean sales only, purchased from the pipeline itself, because of the presence of the words "and sell gas to" in the section.

(2) One policy question is whether an interconnection for the purpose of receiving transported gas should be specifically included. However, once the facility is constructed, it seems almost a given that the facility could be used for transportation as well as, or in lieu of, a sale under open access conditions. Not only would the delivery point be available for open access transportation, but the LDC would likely have conversion rights, with or without a Gas Inventory Charge.

(3) In any event, the basic question remains as to whether any interconnection should be reserved only for sales service by the interstate pipeline and not made available for third party competitors of the pipeline.

(B) Does new Section 7(a)(2) adequately provide for "transportation" of natural gas? According to the analysis provided by the Secretary of Energy, this provision would authorize the FERC to order an interconnection "in order to receive gas from the other facilities for transportation in the pipeline." The following policy questions are raised.

(1) With the use of the words "any person", it appears that mandatory interconnections can be ordered on behalf of a number of classes, including but not limited to: industrial end users; local distribution companies; producers; marketers; gatherers; other interstate pipelines; and intrastate pipelines.

(2) Anticipating the answer to Senator Johnston's Question 2(b), there is no limitation on the interconnection being "upstream" but not "downstream." Leaving aside for the moment the issue of "bypass" by an end user of a local distribution company, it seems clear that the interconnection can be ordered anywhere on the affected pipeline system. This could be in the market area, in the production area, or anywhere in between. For example, a pipeline seeking to increase sales or service related to imports of Canadian gas could seek an interconnection in the market area or near the market area of another pipeline.

(3) Squarely facing the "bypass" issue, it seems clear that an industrial end user could invoke the Commission's jurisdiction to compel an interconnection with an affected pipeline, one that would "bypass" the facilities of a local distribution company.

(4) The limitation in the statutory language "in order to receive natural gas from the petitioner's facilities" carries with it the same implication discussed under (2) with respect to the new 7(a)(1). Here it is clear that transportation gas is included, but for purposes of securing the interconnection the gas supply would move to, not from, the pipeline. Once built, however, given the open access conditions, the interconnection should be available for transportation in, as well as out of, the facility. It may well be better policy to remove the limitation from the statute, so that there will be a clear two way street. For example, if one pipeline is allowed to tap into another pipeline, it is not good policy to make the facility available only for one pipeline's use.

(5) Having responded to the request to indicate the policy issues raised, we respectfully suggest that the proposed section be adopted, with the removal of the initial limitation as discussed in (4). Section 7(a)(3) provides adequate protection for existing customers' service. The only real reason why a mandatory interconnection should have to be sought is because one type of monopoly or another refuses to deal with a customer seeking access to the interstate pipeline system and a gas supply secured from third parties.

Answer to 2(b): The section does not achieve its "stated purpose" of authorizing the FERC to order upstream interconnection but not downstream interconnection, i.e., bypass. First, on its face it includes local distribution companies who will predominantly be "downstream." Further, as set forth above, there is no limitation on the geographical limits of the interconnection authority. It could be anywhere on an affected pipeline.

Answer to 2(c): In the above discussion "technical" questions have already been discussed, and suggestions made. However, in view of Senator Johnston's comments with respect to this section at the hearing of March 7, 1991, we wish to suggest possible substitute language that would achieve his stated goal, even though we do not advocate consideration only of the problems related to the producing areas.

We begin with a background summary.

As a general proposition, lines that originate at the wellheads in the producing areas are classified as "gathering" and therefore are exempt from Section 1(b) of the Natural Gas Act. Passing over a more detailed legal analysis, unless requested, the following situation has evolved:

(1) If the "gathering" lines are owned by an interstate pipeline, then the rates and charges are regulated for the purpose of inclusion in the rates and charges for sales for resale customers, as decided by the Supreme Court in the 1940s. The Commission has held that this principle applies for the purposes of open access transportation, and this holding is under review by the U.S. Court of Appeals for the Eighth Circuit.

(2) If the "gathering" lines have been certificated by the FERC (or the FPC, its predecessor), then the lines can be regulated by the FERC unless and until an abandonment is obtained.

(3) If neither of the above two conditions are met -- that is, if the gathering lines are in the hands of producers or independent gatherers and there is no certificate covering the facilities, then there is no FERC jurisdiction, subject to the outcome of the case in the Eighth Circuit, referred to in (1).

(4) However, whether a particular line is a "gathering" line or is "transmission", with the latter being fully regulated by the FERC, if it otherwise has jurisdiction, is an uncertainty that plagues business planning. This problem is probably more acute in the OCS than onshore, but it is a problem nonetheless. The FERC has jurisdiction to classify the facilities, subject to judicial review.

The problem comes in several subsets, not the least of which involves access to and from "gas processing facilities", where valuable natural gas liquids are extracted from the gas stream, as detailed in the testimony of March 4, 1991, at page 4.

(5) Another problem which must be confronted is the fact that, in some cases, the capacity of an interstate pipeline to "receive" gas into its system far exceeds its ability to "deliver" gas in the market areas, thus raising the question of whether 7(a)(3) would operate as a bar to any mandatory interconnections in the producing areas.

(6) Finally, it must be recognized that, in some areas, the only economic option is access to the existing gathering system of the interstate pipeline, there being no economic alternative to "bypass" the pipeline's own gathering, even if an interconnection with mainline facilities or a plant could, in theory, occur.

(7) In order to address the problem presented, the above factors should be taken into consideration, so that any legislative changes can achieve the desired result. That result is, at a minimum, that there be an access to the interstate market for gas starting at the wellhead. If interstate pipelines have the power to deny interconnections with the "gathering lines" of others or access to their own gathering lines, a monopsony power is fostered. Likewise, when the "gathering line" of another crosses over into the category of "transmission", without an opportunity to interconnect the same monopsony power is fostered.

With the above considerations in mind, the Committee may wish to consider:

(A) inserting the words "or gathering" between "transportation" and "facilities" in 7(a)(2). This would make clear that an applicant has the right to seek interconnection with facilities classified as "gathering" as well as "transportation" facilities, which may be construed to mean only mainline transmission facilities. Thus, even individual well hookups to a pipeline's gathering system could be ordered under this provision;

(B) inserting the words "and transport" between "receive" and "natural gas" in 7(a)(2). It does not achieve the purpose if the pipeline is not obligated to transport the gas received in an interconnection. The pipeline could either (a) shut in, or (b) force a sale to the pipeline;

(C) inserting the words "production or other" between "petitioner's" and "facilities" in two places in 7(a)(2). This would avoid any litigation on the definition of "facilities" and whether wellheads are excluded;

(D) adding a sentence to the end of 7(a)(2) as follows: "Any interconnection ordered pursuant to this subsection, including any facilities upstream of the interconnection, shall be deemed to be 'production or gathering' of natural gas, within the meaning of Section 1(b), unless the interconnection and any facilities upstream are owned by a person who transports natural gas in interstate commerce pursuant to Section 1(b)." The intent here, if achieved, is to preserve a non-jurisdictional status for gatherers other than interstate pipelines and to preempt any litigation as to whether the interconnected facilities are "gathering" or "transmission." This should encourage optimum construction and utilization of facilities for access to production, including access to more than one pipeline;

(E) clarifying that a "natural-gas company" in 7(a)(2) means only an interstate pipeline by adding "which transports natural gas in interstate commerce." Except to the extent repealed either by the NGPA or the Wellhead Decontrol Act, persons who make "sales for resale" in interstate commerce are also "natural gas companies." It was understood that the purpose of this section was not to reach beyond interstate pipeline companies and 7(k) pipeline companies; and

(F) amending section 7(a)(3)(B) to add: "Provided, this subsection shall not apply when an interconnection ordered to or in lieu of gathering facilities pursuant to section 7(a)(2) if the Commission finds that natural supply alternatives to natural gas consumers will be enhanced by the physical connection." This is a legislative finding that service to existing customers will not be impaired by increasing the number of potential sellers and the quantities of potential supply in the production areas. The Commission would, of course, continue to regulate access, so that no customer would be cut off from existing arrangements but would only have more viable alternatives.

These suggestions are tendered only as a result of the perceived duty to respond to this inquiry and should not be taken as any modification of the filed testimony or these answers.

ANSWERS OF F. JOSEPH GRAHAM ON BEHALF OF UNION CARBIDE CORPORATION AND THE PETROCHEMICAL ENERGY GROUP TO SENATOR PETE V. DOMENICI POST-HEARING QUESTIONS, HEARING ON TITLE X OF S. 341 THE NATIONAL ENERGY SECURITY ACT OF 1991

1. **Do you support the Commission's open access transportation program?**

Answer: Yes. We recognize that the promise of open access transportation, with comparable third party transportation service, has not been achieved yet. With the support of this Committee, this goal can be achieved by (a) assuring that comparable third party transportation service is required, and (b) by preventing the abuse of market power, as we suggested in the testimony filed.

2. **If sections 204 and 205 of S. 570 were adopted what impact would that have on the Commission's open access transportation program?**

Answer: Unfortunately, it appears that sections 204 and 205 of S. 570 would actually negate the Commission's open access transportation program. Contrary to the National Energy Strategy itself, these sections do not impose the two essential preconditions: that interstate pipelines provide comparable service to third party shippers and that the interstate pipelines do not have market power. These provisions apparently would reestablish monopoly power over customers and monopsony power over producers of gas.

3. **Would you prefer the NGPA section 311 amendments in S. 341 or those in S. 570?**

Answer: S. 341. This bill codifies open access transportation, a codification that should be imposed on all interstate pipelines, as well as protections against the abuse of market power, the two preconditions found in the NES.

4. **What changes would you recommend be made to sections 203, 204 and 205 of S. 570?**

Answer: We continue to recommend deletion of Sections 204 and 205. As previously stated, we recommend Section 10002 of S. 341 over Section 203 of S. 570.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF THE GENERAL COUNSEL

March 29, 1991

Honorable J. Bennett Johnston
United States Senate
Washington, D.C. 20510

Dear Senator Johnston,

Enclosed is supplemental testimony relating to the National Energy Strategy Act (S. 570) and answers to follow-up questions resulting from the March 7, 1991 hearing before the Committee on Energy and Natural Resources to consider Title X of the National Energy Security Act (S. 341). As stated in my letter of March 19, 1991, the supplemental testimony addresses several questions that were raised at the hearing relating to the deregulation of natural gas imports and gas delivery interconnections which are proposed in the National Energy Strategy Act.

We appreciate the opportunity to submit this supplemental testimony and the answers to follow-up questions, and look forward to working with the Committee in the future.

Sincerely,

Bill Scherman

William S. Scherman
General Counsel

SUPPLEMENTAL TESTIMONY OF
WILLIAM S. SCHERMAN
GENERAL COUNSEL, FEDERAL ENERGY REGULATORY COMMISSION
BEFORE THE COMMITTEE ON ENERGY AND NATURAL RESOURCES
OF THE UNITED STATES SENATE
MARCH 25, 1991

Mr. Chairman and Members of the Committee:

On March 7, 1991, Kevin P. Madden, Director of the Federal Energy Regulatory Commission's (Commission) Office of Pipeline and Producer Regulation, and I appeared as staff witnesses before this Committee to discuss Title X of the National Energy Security Act of 1991 (S. 341), the amendments to that bill that were introduced by Senator Bingaman, and the National Energy Strategy put forth by the Administration. At that time, the legislation to implement the National Energy Strategy, the National Energy Strategy Act (S. 570), had just been submitted to the Congress. Consequently, the Committee requested that we submit supplemental testimony analyzing that legislation. We are also submitting today answers to post-hearing questions posed by the Committee. Questions or requests for comments which were made during the hearing itself were addressed in written responses on March 19, 1991.

THE BILL IN BRIEF

The National Energy Strategy Act (NESA) contains several changes which are intended to streamline the Commission's regulatory process relating to the regulation of natural gas.

For instance, these proposals seek to create two new licensing options: (1) an optional certificate process which would not require a hearing or proof of the public convenience and necessity and (2) a nonjurisdictional option under which a person could conduct various activities without obtaining a certificate from the Commission.

The proposed legislation would also authorize transportation under section 311 of the Natural Gas Policy Act (NGPA) to be on behalf of anyone and would expressly provide authority for section 311 construction. Additionally, it would seek to streamline the Commission's activities under the National Environmental Policy Act (NEPA) by limiting the actions that would require environmental review and by permitting the Commission to charge applicants directly for environmental documentation costs. Finally, the legislation proposes various changes related to the statutory regime governing the import and export of natural gas. A section by section analysis or discussion of the proposals contained in the NESA is set forth below.

SECTION 201: GAS DELIVERY INTERCONNECTION

Proposed section 201 would amend section 7(a) of the Natural Gas Act (NGA) with regard to gas delivery interconnections. Currently, NGA section 7(a) provides that, after notice and opportunity for hearing, the Commission may direct a natural gas company to (1) extend or improve its transportation facilities, (2) establish physical connection of its transportation facilities with the facilities of, and sell natural gas to, any person or municipality engaged or legally authorized to engage in the local distribution of natural or artificial gas to the public, and (3) extend its transportation facilities to communities immediately adjacent to such facilities or to territory served by such natural gas company or person.

The proposed amendment would make this authority apply to any facility which has been constructed, extended, acquired, or is operating a facility under proposed section 7(k), which is the nonjurisdictional option described in proposed section 205. As more fully discussed below, a person constructing, extending, acquiring, or operating a facility for the transportation or sale of natural gas under the proposed nonjurisdictional option does not obtain a certificate, is not considered to be a natural gas company for purposes of the NGA, and may not participate in proceedings to consider competing certificate applications for facilities that would serve the same area as the nonjurisdictional facility.

Proposed section 201 would further amend existing NGA section 7(a) to provide that upon the petition of any person, the Commission may in certain circumstances direct a natural gas company or person functioning under the proposed nonjurisdictional option to establish at the petitioner's expense physical connection of its transportation facilities with the petitioner's facilities in order to receive natural gas from the petitioner.

Finally, section 201 would include for both receipt and delivery point interconnections the existing section 7(a) limitation that the Commission does not have authority to compel the enlargement of transportation facilities, or compel a person to establish a physical connection or sell natural gas, when to do so would impair its ability to render adequate service to its customers.

In order to analyze fully what this proposal entails, it is important to discuss the history of existing NGA section 7(a). The authorization granted to the Commission by NGA section 7(a) is limited. The courts have interpreted and applied these limitations strictly. Thus, in Municipal Distributors Group v. FPC, 467 F.2d 741, 749 (D.C. Cir. 1972), the Court stated:

> A section 7(a) order under the statute alone represents a pure exercise of governmental power on behalf of the potential customer to coerce construction by an unwilling pipeline. We do not believe it would be at all unreasonable for the Commission to demand a far more rigid standard of necessity and convenience from a section 7(a) applicant relying solely on the statute than from an applicant seeking enforcement of a tariff provision.

In another case, where the Federal Power Commission relied on section 7(a) to reallocate pipeline deliveries to the pipeline's public utility customers, the Court reversed the Commission. In doing so, the Court pointed to the statutory limitation which "forbids the Commission to compel a natural gas company to 'sell natural gas when to do so would impair its ability to render adequate service to its customers.'" The Court said that "the theory and purpose of the statutory restriction appears to be that persons desiring gas for the first time or desiring more gas should not get it by taking it away from existing lawful customers." Granite City Steel Co. v. FPC, 320 F.2d 711, 713 (D.C. Cir. 1963).

The statute further limits the Commission's authority in providing that physical connection may only be required to municipalities or local distribution companies, and the pipeline may only be required to extend its facilities to communities immediately adjacent to such facilities or to territory served by the natural gas company and only if no other burden will be placed on the natural gas company. The authority is further qualified by the important prohibition against requiring a natural gas company to enlarge its facilities. Since section 201 proposes language similar to that of existing section 7(a) limitations, the authorization to the Commission would be similarly limited.

In essence, section 201 would first take the authority currently existing in NGA section 7(a), which as relevant here, allows the Commission to order a natural gas company to extend its facilities and establish physical connection with the facilities of any person or municipality engaged in the local distribution of gas for purposes of delivering gas, and extend it to facilities which are constructed, extended, acquired, or operated under the nonjurisdictional option that would be created in proposed section 7(k). Under this authority, the Commission's power to order a natural gas company to alter its facilities applies to the delivery of gas to specified entities. The proposed amendment would extend this authority to order changes in facilities to include facilities functioning under the proposed section 7(k) nonjurisdictional option. Thus, any person or municipality currently able to file for a section 7(a) order to take delivery of natural gas from a natural gas company could use this same limited authority to seek an interconnection with a section 7(c) facility.

In addition, proposed section 201 would then provide that any person may petition the Commission to order a natural gas company or person functioning under the proposed nonjurisdictional option to establish a physical connection with the petitioner's facilities in order to receive natural gas from the petitioner. This would expand the Commission's power, which as set forth above, previously was limited to matters relating to the delivery of gas. Thus, this proposal would enable any person, e.g., another pipeline, producer, or a shipper, to seek receipt of its gas by any natural gas pipeline or person operating under the proposed section 7(k) nonjurisdictional option.

Several questions arise with regard to the proposal providing the right to petition the Commission to direct physical connection of transportation facilities with petitioner's facilities in order to receive natural gas from the petitioner. Unlike the Commission's authority to direct interconnection for purposes of delivering gas in proposed section 7(a)(1), notice and hearing would not be required before the Commission could direct interconnection, pursuant to proposed section 7(a)(2), for purposes of receiving gas from the facilities of another. Also, proposed section 7(a)(1) states that the Commission may direct an interconnection only after finding that such action is "necessary or desirable in the public interest." This standard is not contained in section 7(a)(2). It is unclear whether this standard is intended to be broader than the test used to determine whether to order delivery interconnections. If the drafters intended this dichotomy, the question is whether there are any limitations upon the Commission's authority to direct interconnection for purposes of receiving gas, and if so, the nature and extent of those limitations. In short, under what circumstances could the Commission properly direct such an interconnection? This is particularly important to clarify since proposed sections 7(a)(3)(A) and 7(a)(3)(B) apply the existing section 7(a) limitations to both proposed sections 7(a)(1) and 7(a)(2).

It is important to address this question because, as a general policy matter, any proposal that would add flexibility to move gas through mandated physical interconnections would complement the Commission's efforts to establish an open-access market. However, unless the Commission's authority to order interconnections is clearly expanded beyond existing law, the utility of proposed NGA section 7(a) would be limited at best. In this vein, it would seem appropriate for the Committee to address whether, on policy grounds, it is a good idea to expand the circumstances under which such receipt point interconnects could be ordered. The Committee may also wish to consider whether this section should be expanded to extend to local distribution companies the right to seek delivery interconnections for transportation service as well as sales service. This would increase their options to purchase competitively priced gas and should benefit consumers accordingly. Since this action would not expand the category of companies who could seek interconnection for delivery of gas, no bypass issues would be raised.

In particular, under current law, only local distribution companies and municipalities may use NGA section 7(a) to request an interconnection to purchase gas from a pipeline. They may not use that section to request interconnection for transportation service. An end-user, such as an industrial facility, has no such rights under existing NGA section 7(a). Only if this section were amended to include end-users could a by-pass of a distributor or municipality occur. However, expanding distributors' rights to request a transportation interconnection does not raise this possibility, one to which distributors object because of the potential impact on their residential and commercial customers of losing a major industrial customer. On the contrary, expansion of the distributors' rights could enhance their ability to serve all of their customers, including maximizing the options for their industrial customers.

SECTION 202: NEPA COMPLIANCE

Major Federal Action

With regard to the National Environmental Policy Act (NEPA), section 202 seeks to amend NGA section 7(c) to provide that the issuance of a certificate for construction or extension of facilities "is the only Federal action that is considered a major Federal action requiring preparation of a detailed statement on the environmental impact of the proposed action." In the sectional analysis accompanying the bill, it is explained that the only environmental impact statement (EIS) for a pipeline project required by NEPA is that prepared by the Commission, but that the Commission still would be required to consult with and solicit comments from other agencies.

This proposal represents a potentially important advance in determining what the Commission must do to comply with NEPA, which often constitutes the most time-consuming aspect of review of major projects.

Several aspects of this proposal may need to be clarified, however. First, the actual text of the proposed legislation states that only construction or extension of facilities under authority of an NGA section 7(c) certificate constitutes a major Federal action requiring a detailed EIS. The sectional analysis on the other hand appears to interpret this section to say that the only EIS required for a pipeline project is that prepared by the Commission, which is a completely different thing. The sectional analysis in effect states that only the Commission, and not other agencies, is required to prepare an EIS evaluating a pipeline project. The text of the proposed legislation, on the other hand, purports to limit what constitutes a "major Federal action." As to the statement in the sectional analysis, there already exists the "lead agency" concept, which the Commission has endorsed, whereby agencies may adopt an EIS prepared by the agency with primary jurisdiction over a project; this provision would add little to that concept. Limiting by statute the definition of what constitutes a major Federal action requiring preparation of an EIS to the authorization of construction or extension of facilities by issuance of a certificate on the other hand would be extremely beneficial.

Also, assuming that the literal reading discussed above is correct, it is important to recognize that not all construction or extensions authorized under NGA section 7(c) necessarily constitute major Federal actions requiring preparation of an EIS. It may be advisable to acknowledge, either in the language of the bill or in the conference report, that most construction or extensions for which a certificate is issued do not necessarily constitute major Federal actions and that oftentimes such construction is limited to minor facilities which could require only preparation of an environmental assessment. Put differently, many projects authorized under section 7(c) do not require a full-fledged environmental review culminating in an EIS.

In the same manner, the meaning of the statement that construction or extension of facilities is the only action requiring "a detailed statement on the environmental impact of the proposed action" should be clarified. Again, it seems to be the intent that only construction or extension projects receiving an NGA section 7 certificate would require environmental review. The proposed section, however, is couched in language that is commonly applied only to environmental impact statements and may give rise to the inference that the Commission is still required to conduct an environmental assessment, as opposed to an environmental impact statement, for any project not falling under the purview of this amendment. If so, that would create a significant problem in that environmental assessments are done in the first instance to evaluate whether a further environmental review in the form of an EIS is needed. It would also vitiate the apparent intent of this section to limit environmental review requirements to construction or extension of facilities.

Additionally, as drafted, the bill applies only to projects certificated under section 7(c) and would preclude NEPA review of construction or extension authorizations granted by rulemaking. Clarification of the bill's intent in this regard may be needed.

Finally, as we indicated with respect to S. 341, we would request that the Committee consider our proposal made in the testimony of Cynthia Marlette before the Committee on Energy and Natural Resources of the United States Senate on February 26, 1991. For the sake of convenience, the suggested language is repeated here:

> In cases where Federal Energy Regulatory Commission authorization of the construction or operation of facilities or projects under the Natural Gas Act or the Federal Power Act may be deemed a major Federal action under the National Environmental Policy Act or requires the preparation of other environmental documents, the Commission shall be the lead agency and shall have primary authority for compliance with section 2 and Title I of the National Environmental Policy Act. A review under the National Environmental Policy Act completed by the Commission is the only documentation needed by an agency to satisfy the requirements of the National Environmental Policy Act for the project subject to the review. The Commission may establish reasonable time limits for submission of comments, recommendations, terms, conditions, prescriptions, and reports by a Federal agency, State agency, Indian tribe, and other interested persons. If an agency does not meet the Commission's time limitations, the Commission may continue to process and to take any appropriate action on the application."

Environmental Documentation Costs

The proposed legislation also provides that the Commission may charge an applicant directly for environmental documentation costs the Commission incurs in processing applications for the construction and operation of natural gas pipeline facilities and for hydroelectric licenses and relicenses. Such charges would not be applied against the Commission's annual appropriations.

We welcome this proposal as consistent with the development in the Commission and other agencies to recover from those on whose behalf work is performed the costs of reviewing and processing applications. It might be useful though to provide insight into what is meant by "environmental documentation costs." Would this relate only to costs incurred that result in the production of documents such as an environmental assessment or EIS, or would it relate to all costs of the environmental review, regardless of whether those expenses culminated in some form of documentation?

SECTION 203: AMENDMENT TO NGPA SECTION 311

Construction Authorization and State Notification

As with S. 341, which was discussed in our testimony on March 7, 1991, the National Energy Strategy Act also proposes to amend section 311 of the National Gas Policy Act. First, proposed section 203 would amend section 311 to specifically authorize construction. As stated in our previously submitted testimony, section 311 does not at this time explicitly authorize construction, although it has been interpreted by the Commission as conferring that authority. That interpretation has been upheld by the courts. Specific construction authorization would eliminate any possible uncertainty concerning the existence of that authority and thus constitutes a laudable change.

The substantive construction authorization contained in section 203 provides that upon 30 days notification to the affected State commission, an interstate pipeline may construct facilities for section 311 transportation service. It also provides that the rates, terms, and conditions for services provided through such facilities would not be subject to State regulation.

Under current law, an interstate pipeline may construct section 311 facilities upon notifying the Commission 30 days prior to commencement of construction and complying with the self-implementing environmental procedures contained in the Commission's regulations (section 157.206(d)). The Commission's regulations further provide that within 30 days after commencing transportation, an interstate pipeline must file with the Commission an initial full report containing, among other things, information relating to the identity of the pipeline and its affiliation with any other entities involved in the transaction, a description of the transportation activity, and a statement that the local distribution company (LDC) and the appropriate regulatory agency have been notified of the proposed transaction if such transportation is located within the service area of the local distribution company.

The purpose of the proposed requirement regarding State notification should be made more specific. As noted, it is provided that the rates, terms, and conditions for services delivered through such facilities are not subject to State regulation. If the notification provision is intended to confer some authority to State commissions, or replace altogether Federal authority regarding whether construction may proceed or the terms and conditions of such construction, this needs to be clearly stated. If, on the other hand, the provision is meant solely to require a courtesy notification to the States, it may be advisable to establish that up front so that no inference may be drawn that the States would now have substantive jurisdiction over the section 311 activities of interstate pipelines.

One possibility relating to the State notification requirement is that it is meant to alert the appropriate State as to the existence of potential bypass problems whereby the interstate pipeline would bypass the State-regulated LDC and provide service directly to a consumer within the service area of the LDC. Such notification presents no problem, in and of itself, as long as the potential jurisdictional problems raised above are taken into account.

Further, clarification may be warranted as to what type of construction, or resulting transportation, constitutes "affecting" a State commission, thereby invoking the 30 day notification requirement. Also, given the fact that the subsection specifically authorizing construction applies only to interstate pipelines, clarification is needed as to whether this bill intends to preclude construction of section 311 facilities by intrastate pipelines.

The uncertainty surrounding proposed section 203 with regard to whether section 311 construction by interstate pipelines ceases to be a Federal action is compounded by the fact that section 203 provides that transportation may be authorized by rule or order. No such provision, however, is made in the proposed language authorizing construction of section 311 facilities. By contrast, section 10002 of S. 341 provides that the Commission may authorize construction or transportation by rule or order. This omission in section 203 potentially gives rise to a major concern. Not allowing construction to proceed by rule or order as proposed in section 203 could deny pipeline companies the option of satisfying environmental requirements through the use of self-implementing procedures such as those contained in the Commission's regulations (i.e., section 157.206(d)). Those regulations, in conjunction with self-implementing construction, has allowed the Commission to establish a program for a relatively simple, expeditious approach to the construction of facilities which do not have a significant adverse impact on a sensitive environmental area.

The sectional analysis accompanying section 203 does not address these questions. It does suggest that substituting State notification for Commission notification would absolve the Commission of the need to comply with NEPA for construction of individual projects under NGPA section 311. If this is what is intended, it may be advisable to explicitly state in the proposed amendment that notification would only be to the State and that section 203 would negate all Commission environmental responsibilities for such projects, including those arising under NEPA.

Further, we would note that section 203 would amend section 311 to provide that the Commission shall, by rule or order, authorize the transportation of natural gas. NGPA section 311 currently provides that the Commission may, by rule or order, authorize such transportation. Thus, this proposal appears to require the Commission to grant section 311 authorization whenever it is sought. Further clarification of this point would be helpful, especially in the context of the questions raised above regarding the continued existence and nature of Commission authority over such facilities.

In sum, we strongly endorse removing restrictions on the use of the section 311 authorization. This would enable pipelines to construct facilities more quickly and should increase pro-competitive forces the Commission wishes to foster in the marketplace. Indeed, many of the pro-competitive objects of the proposed optional certificate and nonjurisdictional options could be accomplished by removing the limitations currently in section 311 and expanding the scope of that section. However, it would be helpful if it were clarified regarding the notification that must be provided to the State commission, what can or must be done by them with regard to section 311 construction, and what, if anything, can or must be done by the Commission. Also, would construction and operation activities be subject to State regulation even though rates, terms, and conditions would not?

"On Behalf Of" Authority

As is the case with the proposal contained in section 10002 of S. 341, NESA section 203 would remove existing restraints requiring that transportation must be "on behalf of" certain entities. Proposed section 203 would allow interstate and intrastate pipelines to transport natural gas "on behalf of ... any other person," in addition to the currently designated entities. As explained in the sectional analysis accompanying the proposed legislation, allowing "any person" to avail themselves of section 311 would allow marketers and end-users to become parties on whose behalf section 311 transportation may be performed. As noted in our previous testimony, this would eliminate distinctions between those permitted to avail themselves of this service and should allow for greater competition in the gas industry, while facilitating the open access policy adopted by the Commission. Moreover, this would restore section 311 authority to the competitive role it played in the marketplace prior to the Commission's market-oriented interpretation of the "on behalf of" test being struck down by the court.

One comment in this regard, however, relates to the listing of whom natural gas may be transported "on behalf of." It may be advisable to provide solely for transportation "on behalf of any person," rather than retaining the existing classifications (e.g. interstate pipelines and intrastate pipelines) and then adding "any other person." There appears to be no meaningful reason for retaining the existing classifications; substituting the recommended language may be less confusing.

Finally, given the history of section 311, it might be helpful to specify whether, as proposed to be amended, it would apply only to minor facilities, or if that authorization could be used to construct projects of any size. We believe that this is the intent of the legislation but it may be helpful to clarify this point.

Rates

The question of how rates would be set pursuant to revised section 311 remains unsettled under the proposed legislation. Section 203 provides only that rates, terms, and conditions would not be subject to State regulation. The issue remains as to how and by whom those rates would be set. Presumably, the Commission would set the rates under the just and reasonable standard of the Natural Gas Act, as is currently the process. This should be made clear in light of the other changes to section 311.

Also, as a general comment and as touched upon in our testimony of March 7, 1991, the proposed modifications to section 311 raise the much broader question of what Commission authorizations should exist to best serve the dual mandates of assuring the public interest and allowing for the expeditious construction of pipeline facilities. In this case, if section 311 authorization could be used by everyone, do compelling reasons still exist to retain separate NGA and NGPA authorizations? In many cases, the proposed changes result in the blurring of traditional distinctions to the point that they are often virtually indistinguishable. Indeed, other than not conferring eminent domain authority, section 311 construction as proposed would be extremely similar to section 7 authorization. This makes it all more the important that the desired authorization structure be carefully weighed.

SECTION 204: OPTIONAL CERTIFICATE PROCEDURES

Procedural Aspects

Another innovative aspect of the proposed legislation is section 204 which would amend NGA sections 4 and 7 to allow the Commission to issue what would be called an optional certificate. Under this proposal, which would be enacted as NGA section 7(i), the Commission would authorize construction or extension of facilities if certain terms and conditions are attached to the certificate. Under these terms and conditions, the applicant would not be able to include any costs or expenses it incurs in relation to the operation, sale, service, construction, extension, or acquisition of such facilities in any NGA section 4 rate schedule. Also, the holder of an optional certificate would be precluded as a matter of law from participating in any proceedings under the NGA to consider competing applications for certificates for the construction or extension of facilities that would serve the same area serviced by the holder of the section 7(i) certificate.

The Commission could issue under another part of the proposal a certificate authorizing the acquisition or operation of any facilities: (1) for which a certificate for construction or extension has already been issued under this subsection, or (2) for which abandonment of facilities or services has been approved under section 7(b), as long as the conditions described above are imposed. The statement in (1) above that the Commission could issue a certificate authorizing the acquisition or operation of facilities for which a certificate has already been issued seems to relate to optional certificates granted under color of proposed NGA section 7(i) itself and not to any other certificates authorized by existing NGA section 7. In the case of certificates issued under existing NGA section 7 authority, abandonment would first have to be approved by the Commission pursuant to existing NGA section 7(b). It is unclear what findings the Commission would be required to make in the event that abandonment were sought for purposes of this proposed subsection. Would the Commission's traditional abandonment standards be applicable or is some other standard contemplated?

The proposed optional certificate would not require a hearing or proof that the public convenience and necessity would be served by the facilities. Additionally, such certificates would be non-exclusive and non-prejudicial to an application for any other authorization under the NGA or NGPA. This latter provision raises the question of whether such certificates would be non-exclusive and non-prejudicial to other section 7(i) certificates. While this provision may expedite construction of pipeline projects by companies who choose to avail themselves of it, if such certificates precluded consideration of competing section 7(i) certificates, certain due process concerns might be raised which should be considered. In our previous testimony before this Committee we noted the existence of potential constitutional problems concerning this issue and include that discussion here by reference. In sum, while we believe that limits can and should be placed on the right to a comparative hearing, total elimination of that right in all circumstances may be subject to attack.

Equally important, many questions arise as to the mechanics of how the proposed optional certificate would work. For example, would the Commission have discretion not to issue the optional certificate? The language of the proposed amendment provides that the Commission shall issue a certificate without a hearing or further proof that the public convenience and necessity would be served. Could the Commission examine the public convenience and necessity if there were some compelling reason to do so? Could it condition the certificate if needed and what restraints or limits would exist on its powers to impose such conditions? What form of environmental review is contemplated if the Commission does not have discretion to deny such certificates?

Rates

Proposed section 204 also provides that a rate or charge made, demanded, or received by any natural gas company in connection with the transportation or sale of natural gas through facilities authorized under section 7(i) would be just and reasonable and would comply with NGA section 4(b) (prohibiting undue preferences and unreasonable differences) if the natural gas company and the person paying the rate or charge mutually agree to the rate or charge. Further, proposed section 204 would amend NGA section 4 to provide that subsections 4(c) (requiring the filing of a rate schedule), 4(d) (prohibiting changes in rates or charges except upon 30 days notice), and 4(e) (authorizing a hearing upon the filing of a new rate schedule) would not apply to the transportation or sale of natural gas through facilities authorized under proposed section 7(i).

With regard to the merit of such contract rates, the comments we made in our testimony on March 7, 1991 regarding the potential competitive concerns arising from such rates are relevant here and is incorporated by reference. Briefly summarized, rates negotiated at arms-length in a competitive market should be encouraged. If rates are negotiated in this type of competitive environment, they truly will be market based rates. However, such rates may not always be in the public interest if the contract and rate were obtained through coercion because the pipeline possessed market power. This might be especially true in the case of affiliates that may function as the alter ego of a company or lack sufficient independence to negotiate an arms-length agreement. Also, we note that because such rates are secret, it may be difficult for other companies to know if they were being discriminated against. How could a company paying traditional rates know whether or when to file a complaint?

The fundamental premise underlying unregulated rates for new pipeline construction is that before construction (ex-ante) competition among builders will assure just and reasonable rates for shippers. However, based upon the current level of non-wellhead competition in the industry, this may not always be true. For example, an existing pipeline may be able to expand capacity very cheaply by adding compression, whereas a new entrant would have to lay a new and much more expensive pipe. In this case, the existing pipeline company may be able to use its market power to effectively preclude potential competition from other builders. Similar problems occur with respect to looping existing lines.

Furthermore, the number of potential builders may be limited because of an inability to interconnect with existing pipelines. If a new pipeline can only be viable if it interconnects with an existing pipeline further downstream in the distribution chain, then the existing downstream pipeline, or its affiliates, may be able to exercise market power.

Such problems can be addressed. For example, in order to promote fair and open competition among all potential market participants, an "open tap" policy that requires pipelines to permit interconnections, so long as doing so does not impair their ability to provide service to existing customers, could be considered. Such a pro-market policy would increase the number and competitiveness of potential builders. This could be done by clarifying proposed section 7(a), as discussed earlier, or through a new provision in section 7. To further enhance competitive alternatives, the Commission has used "open seasons" for both builders and shippers. Under such a procedure, an application to build under proposed section 7(i) would be publicly noticed and a brief waiting period established before issuance of the certificate. During this period, other builders would have an opportunity to file competing applications and to compete for shippers. At the end of the brief waiting period, all applicants who agree to the conditions would be issued certificates at the same time.

Complaint Procedure

Proposed section 204 also provides a complaint procedure in a new NGA section 7(j). This procedure applies to services rendered through proposed sections 7(i) and 7(k). The proposed amendment provides with regard to rates that if the Commission, after a hearing upon the petition of a person who has made a bona fide offer to enter into a contract, finds that failure to provide the requested rate in connection with transportation through facilities functioning under an optional certificate or the nonjurisdictional option is unduly discriminatory, the Commission shall determine rates that are not unduly discriminatory and fix them by order. The sectional analysis states that this would not be a cost-based, just and reasonable standard, but would only be a requirement to provide a similar rate for similar service. However, the Commission's authority to order service is limited to situations where capacity is available.

The question of what standard the Commission would apply to determine rates that are not unduly discriminatory is an important one and should be clearly set out in the legislation. Moreover, the comment in the sectional analysis that the rates determined by the Commission would not be fixed according to a cost-based, just and reasonable standard, seems to conflict with the statement in section 204(a) that a rate or charge in connection with the transportation or sale of natural gas through facilities authorized under the optional certificate procedure is just and reasonable if the natural gas company and the person paying the rate or charge mutually agree to the rate or charge.

Various other concerns also arise with regard to this procedure. Since such rates would not be on file with the Commission, it may be difficult for a complainant to know the basis for formulating a complaint (other than refusal to serve). From the perspective of the optional certificate or nonjurisdictional option company that may have to provide service pursuant to rates which may be subject to refund, the benefits of the secret rates may be lost. Also, the potential would appear to exist for systems to be segmented between section 7(c) authorization and the proposed authorizations under sections 7(i) and 7(k), which could result in simultaneous proceedings under conflicting standards.

Another matter that remains unclear is that statement in the proposed amendment creating NGA section 7(j)(1) that the undue discrimination standard would apply to certificates issued under section 7(k) (the proposed nonjurisdictional option), as well as to those issued under section 7(i) (the optional certificate). The problem is that no certificate is issued under section 7(k); in fact, the entire thrust of that proposal is to eliminate the certificate procedure, and thus Commission jurisdiction over such facilities and activities. Further, unlike the optional certificate procedure, the nonjurisdictional option does not provide for filing a petition to contest the terms and conditions of service as unduly discriminatory. This matter should be clarified.

There is another issue with respect to the application of the section 7(j) procedures to section 7(k) facilities. On its face, proposed section 205 (discussed in greater detail below) establishes a nonjurisdictional option, and would appear to confer no jurisdiction whatsoever. Yet, by implication, the complaint procedure suggests that if the Commission makes a finding that rates are unduly discriminatory, then those rates would be subject to Commission jurisdiction. If this is so, how would the Commission set those rates and what standard would it use to determine if they are unduly discriminatory? Would those rates be subject to NGA sections 4 and 5, with all their accompanying case law? What would be the difference between a finding that the rates are not under our jurisdiction and a finding that they are just and reasonable, for example. Is this a passthrough (i.e., state review) issue? Would the Commission use a different standard for the two methods?

Upon the filing of a petition claiming that rates are unduly discriminatory, the Commission would issue an order within 60 days directing the requested transportation service to commence on the terms sought, unless it determines that the capacity, in whole or in part, is not available to provide the transportation service. The bill is unclear as to whether the Commission, upon finding that the requested capacity is not available, is required to issue an order to that effect or whether inaction by the Commission serves as a finding of lack of capacity.

Further, if within the 60 day period, the person against whom the petition is filed responds by filing rates it considers to be not unduly discriminatory, the requested service shall commence 60 days after the filing of the petition, based upon the rates filed in response, except if capacity is not available. Any such rate or charge in excess of those requested in the petition is subject to refund if the Commission finds, after hearing, that it is unduly discriminatory. The burden of proof to show that any rate or charge in excess of those filed in the petition is not unduly discriminatory is upon the pipeline.

As set forth above, while this proposal merits serious consideration for its pro-competitive intent, many issues remain unresolved with regard to how the proposed optional certificates would actually work, and whether additional measures are needed to foster competition in the gas industry.

SECTION 205: NONJURISDICTIONAL OPTION

Section 205(a)

The proposed legislation would also provide in section 205(a) a further option under NGA section 7 to be known as the nonjurisdictional option. Under this proposal, a person may elect to construct, extend, acquire, or operate a facility for the transportation or sale of natural gas without obtaining a certificate. If a person elects to proceed under this option, it would not be a natural gas company for purposes of the NGA and it would be precluded from participating in any NGA proceeding to consider an application for a certificate to construct or extend competing facilities. Also, while the construction or extension of a facility authorized under this subsection may be subject to State regulation, the rates and charges for the transportation or sale of natural gas by such a facility would not be subject to State regulation unless those activities took place solely within a State's boundaries under NGA section 1(c).

Under this option, it appears that the construction of facilities would be entirely outside the Commission's jurisdiction, as well as that of the States except under limited circumstances. In this regard, the sectional analysis states that no Federal right of eminent domain would attach to facilities constructed or extended under this provision.

It is also stated in the sectional analysis that since no Commission action would be required for the construction of such facilities, any environmental review would be by State or other Federal agencies. While the Commission apparently would be relieved of all responsibility to conduct an environmental review under this option, other Federal and State agencies would be obligated to conduct such reviews as recognized in the sectional analysis. Receiving the requisite State and Federal approvals, rights of way and permits is often the most time-consuming element of construction. Therefore, this procedure may not necessarily result in completion of projects in a more timely fashion.

A final issue relates to the fact that under the proposed nonjurisdictional option a person may elect to acquire a facility for the transportation or sale of natural gas through that facility without a certificate. Presumably, abandonment authority would be required for a facility certificated under NGA section 7 and the traditional standards relating to abandonment would apply.

Section 205(b)

Section 205(b) would amend existing NGA section 4 to provide that the Commission would be authorized to issue an order finding that rates charged by a natural gas company in a market are not within the Commission's jurisdiction under the NGA if, after a hearing upon the application of a natural gas company, the Commission finds that the market is competitive and that the natural gas company offers transportation or sales service to that market on a basis which is not unduly discriminatory. It is stated in the sectional analysis that this authority is in addition to the Commission's existing authority to determine that market-based rates meet the just and reasonable standard when sufficient competition exists to protect consumers from market power abuses.

Although this amendment to NGA section 4 is located in the same section as the nonjurisdictional construction option, it appears to pertain only to facilities subject to the Commission's jurisdiction. That follows from its application to "natural gas companies." Accordingly, its intention is the deregulation of existing (or subsequently certificated) interstate pipelines' sales and transportation rates. With respect to sales rates, the amendment is in accord with the Commission's efforts to establish market-based rates in the context of its gas inventory proceedings. The Commission has permitted such sales rates only when it has found sufficient divertible supplies and comparability of transportation and sales service to ensure that the pipelines do not possess market power. To date, however, the Commission has not had the opportunity to address the deregulation of pipelines' transportation rates. In large part, this is due to the predominantly monopolistic configuration of the existing interstate pipeline grid. In fact, the continued regulation of pipelines' transportation rates has been an important factor in the Commission's determinations that pipelines' sales rates require less regulatory scrutiny.

In addition to the observation above on the importance of the regulation of pipelines' transportation rates to the deregulation of their sales rates, a major concern with regard to this proposed amendment is what happens if, once rates are deregulated, circumstances change such that the market the natural gas company is authorized to serve is no longer competitive and the transportation or sales service is no longer offered on a basis that is not unduly discriminatory. Would the Commission be able to reassert jurisdiction over those rates and charges? If so, what would be the jurisdictional predicate for the exercise of that authority?

SECTIONS 211, 212, 213: NATURAL GAS IMPORT/EXPORT DEREGULATION

Subtitle B of the National Energy Strategy Act, comprising sections 212, 213, and 214, proposes certain changes pertaining to the regulation of imports and exports of natural gas, which would in effect deregulate those activities. In accordance with the request at the hearing of March 7, 1991, comments on that aspect of the proposed legislation are set forth as follows.

Prior to 1977, jurisdiction to regulate natural gas imports and exports under NGA section 3 was vested in our predecessor agency, the Federal Power Commission (FPC). In 1977, Congress vested exclusive jurisdiction to decide import and export issues arising under section 3 in the Secretary of Energy, pursuant to §§301(b) and 402(f) of the Department of Energy Organization Act. 42 U.S.C. §7152(a), 42 U.S.C. §7172(a). The Secretary thereafter delegated and divided section 3 authority between the Administrator of the Economic Regulatory Administration (ERA) and the Federal Energy Regulatory Commission (FERC), pursuant to a series of delegation orders.

Pursuant to the Secretary's delegation orders, the Administrator of the ERA was given exclusive jurisdiction under section 3 to authorize imports and exports of gas. ERA import/export authorization is dependent upon considerations of, among other things, the competitiveness of the import, the need for the gas, the security of supply and any other appropriate matters. By order issued February 7, 1989, the Secretary transferred the authority to regulate natural gas imports and exports held by the ERA to the Assistant Secretary for Fossil Energy (DOE/FE).

The Commission was delegated jurisdiction under section 3 to approve or disapprove the construction and operation, including the site at which the facilities are located, of particular facilities incidental to the importation of natural gas. The Commission also has the authority to perform all functions under sections 4, 5, and 7 of the NGA.

Section 212 of the proposed bill would rewrite section 3 in its entirety and would, in effect deregulate the international gas market. At the same time, the definition of interstate commerce in section 2 of the NGA would be revised to include natural gas following importation or preceding exportation. This would eliminate the previous distinction between "interstate commerce" and "foreign commerce," as defined in various court decisions. See, Border Pipe Line Company v. FPC, 171 F.2d 149 (1948); Distrigas Corporation v. FPC., 495 F.2d 1057 (1974). The sectional analysis appropriately points out that, under this proposal, gas imports would be treated in the same manner as domestic natural gas production and gas exports would be treated as gas sold to any consumer. However, it should be noted here that gas imports would not be subject to the regulatory restraints of NGPA Title I and NGA section 7, as would certain domestic production. Of course, the final step in wellhead deregulation, effective January 1, 1993, pursuant to the Natural Gas Wellhead Decontrol Act of 1989, would erase these residual distinctions between imported gas and domestic production.

Further, under section 3, as presently written, and the pertinent delegation orders, the Commission approves the site of construction of border facilities to be used to import or export gas. The proposed legislation would remove Commission review of these facilities under section 3. However, while the bill removes section 3 authority to review these construction projects, by including imports and exports in the definition of interstate commerce in NGA section 2, the proposed bill would result in mandating Commission review of the construction of these facilities pursuant to NGA section 7(c), as with any other construction of facilities to be used in interstate commerce.

However, there would be instances where the Commission's section 7 review authority would not apply. For instance, if a company planned to construct facilities from the border to a certain point within the same state (in other words, no state line would be crossed) to transport imported gas that would be consumed within that state, the construction of facilities would be exempt from section 7 review by virtue of NGA section 1(c).

However, if instead, the pipeline extended across a state line, section 7 jurisdiction would attach for the full length of the pipeline, i.e. from the border to the end of the pipeline.

That sales of imported gas would be treated the same as domestic production is highlighted by the amendment to section 3 which states that importation of natural gas is considered a "first sale." The deregulation of international gas trade is completed by the proposed section 3 provision which would bar the Commission or any state from prohibiting or conditioning the importation or exportation of natural gas.

The proposed revisions to section 3 set forth authority for the President to prohibit or condition importation or exportation of gas if required by the national interest. The President would also be given authority to waive any law relating to the import/export of natural gas or specify by schedule or otherwise, when a particular pertinent law is satisfied. The sectional analysis states that this provision is intended to allow the President to intercede to facilitate a project, if required by the national interest. The necessity for these provisions is not clear. In addition, the precise meaning of terms such as "national interest" should be explained. Furthermore, it is unclear whether this proposal would confer upon the President the authority to waive any laws, such as the Free Trade Agreement, if it was in the national interest.

CONCLUSION

In conclusion, as stated in our previous testimony, we respectively submit that in many ways the legislative proposals currently under consideration seek to build upon the progress the Commission has made to promote competition in the gas industry and to streamline the regulatory process. We continue to believe it is important that the overall question of what Commission authorizations should exist to fulfill the mandates of assuring the public interest and expediting pipeline construction be carefully considered. We stand ready to assist the Committee in any way we can on this vitally important matter.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 1A: There have been several efforts by FERC, and parallel legislative proposals, to provide for deregulation or simplification of the regulation of natural gas pipelines which are found by FERC to serve "competitive" markets. In determining whether competition exists in a market, does FERC look only at whether there are alternative natural gas pipelines into the market?

Answer: The focus of FERC's competitive analysis for natural gas pipelines has been on the resale of natural gas ("the merchant function") and not whether there is competition in the transportation of the gas to market ("the transportation function"). These analyses, usually done in the context of gas inventory charge ("GIC") proceedings, focus on whether customers have effective alternatives to buying gas from the pipeline. The competitive analysis focuses on whether the pipeline's transportation of third party gas is comparable to the transportation service embedded in the pipeline's bundled sales service, whether the transportation gives customers access to wellhead markets on competitive terms, and whether there is competitive third party gas supply available. Thus, a market which is served by only one pipeline may be competitive for the merchant function but not for the transportation function.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 1B: Isn't oil a source of competition for natural gas in many uses?

Answer: For certain markets and services, primarily industrial boiler and power generation, oil and natural gas do compete. Generally, for environmental and technical reasons, the competition is between the more expensive grades of oil products like distillate (number 2 oil) and low sulfur residual oil (number 6 oil) and natural gas. In recent years, the relative prices of these oil products and gas have resulted in gas being the preferred fuel. Generally those facilities which have both gas and oil burning capability have been burning gas except for those times when service was not available.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 1C: Wouldn't it make sense, if one of the purposes of our energy policy is to promote displacement of oil, to consider the presence of oil fuels in a market?

Answer: It is difficult to generalize the extent to which oil effectively competes with natural gas from market area to market area. As noted in the answer to Question 1B, oil and gas do compete in certain uses and in certain markets. In many markets, however, oil may not compete effectively when gas is an available alternative and at a lower price. As a general matter, there are few, if any, facilities which have access to gas that choose to burn oil. In most cases, oil is used as a backstop for situations when gas is not available, such as when transportation is interrupted or for the unusual periods when oil is cheaper than gas.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 1D: Why wouldn't FERC consider trans-fuel competition?

Answer: FERC does consider in its market analysis whether oil and gas are sufficient substitutes in the same product market. In situations like those that exist in today's fuel markets, where gas is often significantly lower priced than oil, the existence of a competitive alternate to gas is often not sufficient to ensure that pipelines do not detrimentally exercise market power. However, the Commission does examine on a market by market basis competition from all sources to determine the level of competition in that market.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 1E: Why is natural gas now priced at half the already low cost of oil on an energy-equivalent basis?

Answer: For a variety of reasons, gas and oil prices are effectively decoupled. For instance, the price of oil is set in the world market, while gas prices are set in the North American market. While there is a degree of substitution between oil and gas, this potential overlap in their markets is currently not sufficient to overcome the substantial differences in the supply/demand situations in the individual markets. For the past several years gas supply has exceeded gas demand. However, gas demand is likely to increase as a result of the Clean Air Act Amendments; demand could increase even further if Congress amends the Public Utility Holding Company Act as proposed by Senators Johnston and Wallop and in S. 570.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 1F: Doesn't the low price of gas compared to electricity and oil seem to indicate it is highly vulnerable to competition from those energy sources?

Answer: Compared to oil, natural gas has many advantages. It is environmentally cleaner, easier to burn, requires less equipment maintenance, and requires no fuel inventory stocks. Its "in-use efficiency" (*i.e.*, useable Btu per Btu delivered) is comparable to oil products. Consequently, the burner-tip price of gas could rise to the burner-tip price of oil products without losing market share. The fact that the price of gas now is low compared to oil prices indicates that gas is much more vulnerable to competition from other sources of gas than to oil.

Electricity has all the same advantages as gas, with one exception: electricity's "in-use efficiency" is higher than that of gas. Generally, electricity is more efficient than gas at the point of consumption. While prices vary regionally, the average delivered price of electricity is roughly $20/MMBtu, compared to delivered gas prices of less than $6/MMBtu for residential customers and $3/MMBtu for industrial customers.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 2A: What legal and regulatory barriers face pipelines which wish to collaborate to fix and market a "postage stamp" rate from producer to end-user, across several companies' pipelines?

Answer: The rates of each pipeline would be subject to review under sections 4 and 5 of the Natural Gas Act to determine whether the rates are just and reasonable and not unduly discriminatory. This review would include an examination of the lawfulness of any discounts. The pipelines would have to establish that any discounts given were necessary to meet the competition present in the market place. In addition, the collaboration by pipelines to establish joint "postage stamp" transportation rates by, for example, joint discounting, would be subject to potential review under the antitrust laws.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 2B: In your opinion, is FERC capable of preventing abuses of collaboration in such cases through its ability to examine ratemaking and to examine competitive issues?

Answer: Yes. The FERC can prevent abuses of collaboration through its authority to examine pipeline rates to determine whether they are lawful under the Natural Gas Act. As part of that determination, the Commission has the ability to and does examine competitive issues. Thus, for example, if a pipeline is found to have inappropriately used its pricing flexibility, the Commission can remedy the abuse prospectively by removing the pipeline's rate flexibility and requiring the pipeline to charge only the stated rate on file with the Commission. In addition, the Commission must take into account the policies underlying the antitrust laws when it exercises its Natural Gas Act responsibilities.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 2C: Would you then support minor modification of the anti-trust laws to make such collaboration more feasible?

Answer: The Department of Justice has the expertise to analyze whether this proposal is feasible under the antitrust laws. However, we would not oppose any modification that would allow for greater competition in the gas industry.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 3A: Are there reasonable alternatives to basing pipeline rates on the original cost of the investment, which results through depreciation in particularly low rates for older pipelines?

Answer: There are a number of alternative approaches to valuation of pipeline assets which could be used as a basis for determining pipeline rates. Among these are: incentive ratemaking; negotiated rates; replacement cost less accumulated depreciation; undepreciated replacement cost; and capitalized valuation of earnings (fair value of assets).

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 3B: Isn't the depreciation of these pipelines highly artificial, as their value is more akin to their replacement or sale value?

Answer: Depreciation may be "artificial" in the context that depreciation rates are not determined on the basis of cumulative usage or wear that has occurred. The application of the concept of depreciation serves useful purposes for financial accounting, cash flow determinations to support a project's ability to repay borrowed capital, and taxation (income, ad valorem, etc.), as well as for regulating rates.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 3C: Wouldn't the public benefit overall from a policy which allowed a greater return from older pipes and lower rates from new construction?

Answer: The Commission does not consider the age of a pipeline when establishing a rate of return; rather, the Commission considers the pipeline's financial structure, such as the cost of debt and equity and the operating environment. Lower return for new construction might discourage needed pipeline expansions. Depending upon the circumstances, the return may not be high enough to attract needed investment in new facilities. Giving a higher return for older pipelines compared to new construction may also provide an incentive for investors to invest in existing pipelines through mergers or takeovers rather than encouraging investment in necessary pipeline expansion. On the other hand, the Commission has considered proposals that would levelize the rates over the life of the project, thus reducing the front-end load associated with the rates for new pipelines using more traditional cost of service principles.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 3D: Doesn't a rate design which makes newer pipes so much more expensive to use than older ones retard the development of new pipeline capacity?

Answer: A traditional rate design that utilizes the pipeline's undepreciated rate base would make new pipelines more expensive than older pipelines. However, as noted in response to Question 3A, there are a number of alternative rate designs. Recently, many of the proposed new pipelines such as Wyoming California and Kern River have used levelized rates. Under a levelized rate, the rate is kept at a constant level for an extended period, much like a mortgage payment. The initial rate is lower than would result from traditional rate design; the rates in later years would be higher than would result from a traditional rate design.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 4A: Rates for transportation and sales service are currently constrained by FERC to the lower of cost or market value. Does failing to allow capture of the market value distort the market, particularly during times of peak demand?

Answer: The term "market value" has numerous meanings, including the value that a monopolist could extract from its customers. The capture of "market value" so defined would cause market distortions. Alternatively, the "market value" can be defined as efficient rates which ration capacity at times of peak demand and maximize throughput at other times. Designing efficient rates was adopted by the Commission as a goal in Order No. 436 and reiterated in the Commission's Rate Design Policy Statement. Determining what rates will be efficient is a difficult task and the implementation of efficient rates may sometimes conflict with other Commission goals, but efficient rates are a major policy issue in all general Natural Gas Act section 4 and 5 rate cases before the Commission.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 4B: Doesn't this amount to subsidizing peak demand?

Answer: Not necessarily. A subsidy would exist if costs were incurred for a peak service but were recovered from a separate service. A gap between "market value" and the peak service rate would not be considered a subsidy if the peak period rate fully recovered all costs legitimately incurred for that service. The Commission recognizes, however, that the process of matching cost incurrance with revenue recovery is an inexact art. The Commission has encouraged the participants in its rate proceedings to develop different cost assignment or allocation methodologies which would more closely match rates with market value based on the guidance provided in its Rate Design Policy Statement.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 4C: Wouldn't this lead to inefficiencies throughout the gas system, including underutilization of existing non-peak pipeline capacity?

Answer: If a peak period rate was below market value while the off-peak rate was above market value, inefficiencies in the gas system could occur, including underutilization of existing non-peak pipeline capacity. Again, this is one of the concerns expressed by the Commission in its Rate Design Policy Statement. The Commission has directed parties in current and future rate cases to explore methods which would identify and remedy inefficient rate design methodologies.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 5A: Would you support allowing flow through of producer demand charges?

Answer: The as-billed flow through of producer demand charges is one of a variety of options the Commission has considered for passthrough of gas costs from producers to pipelines. In fact, the Commission permitted as-billed treatment of such costs for a few pipelines for a short period of time pending the outcome of a public conference held to address this issue. Based upon the comments received and upon further consideration of this issue, the Commission concluded that as-billed passthrough of producer demand charges should only be permitted when it has been established that a pipeline's transportation service is of a comparable quality to its sales service. This will also be addressed in the pipeline service obligation/comparability of services Notice of Proposed Rulemaking the Commission will be considering at a public conference on May 10, 1991.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 5B: Is a producer demand charge any less valid than a gas inventory charge or storage charges?

Answer: The producer demand charge is a no less valid method of collecting a pipeline's costs of securing long-term supplies than is the gas inventory charge method, which also requires a demonstration that a pipeline's transportation service is of a quality comparable to its sales service. Storage charges are an equally valid expense, however they do not serve the same purpose as the first two items.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 5C: Don't these all serve the same economic function?

Answer: The gas inventory charge and the producer demand charge are both associated with the cost of securing long-term supplies to meet the total needs of the customers on a pipeline's system. However, system storage is not as specifically related to an individual customer's nominations as are gas inventory charges or producer demand charges. For the most part, storage is used to meet peak requirements. This allows pipelines to serve customer needs without having to expand pipeline capacity to service peak use needs. Additionally, storage serves the function of allowing gas to be kept in closer proximity to the locations where it ultimately will be used. This permits the gas to be supplied during peak need periods more expeditiously than if it were to be transported from the production fields.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 6A: In your testimony, you stated that environmental analysis was the pacing element in pipeline applications. Please provide us with any figures, studies, or anecdotal examples you can provide to back this up.

Answer: Attached are two studies recently prepared for the General Accounting Office. These studies show the range and average time period required to complete the environmental analysis of pipeline projects.

February 15, 1991 memorandum on "Preparation of Environmental Assessments".

March 12, 1991 memorandum on "Preparation of Environmental Impact Statements".

It should also be noted that these studies represent the average processing time. As stated in the documents, the processing time may be affected by various factors, including incomplete applications, the filing of related applications as part of an integrated project, Ashbacker doctrine considerations, pending rate cases, settlement discussions, or formal hearings.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

February 15, 1991

Memorandum To: Chuck Wilson, GAO

From : William H. Marmura, FERC

Subject : Preparation of Environmental Assessments

The attached study is responsive to your request relative to preparation of environmental assessments for FY88 - FY90.

This report discusses the preparation of written or formal environmental assessments (EA) completed during FY88 through FY90. GAO asked for this information in order to evaluate the length of time it has taken to prepare written or formal EAs during this time period. Excluded from this evaluation, at GAO's requests, were cases where The Commission's environmental review did not produce a formal or written EA, such as categorical exclusions, etc.

After analyzing the data, on average the process takes approximately 180 days from the date of the filing of the application to the date of completion of the EA. As part of the administration of the environmental review process, it usually takes 7 days for routing of the application to the first line environmental analyst. An initial analysis is performed to determine whether the environmental part of the application is ready for processing. In some cases, applications do not contain all necessary environmental exhibits. Staff would advise the applicant to submit the required information. In other cases, companies had to file related applications before an environmental analysis of all aspects of an integrated project can be completed. There are also situations where non-environmental factors preclude environmental analysis of an environmentally complete application. For example, some applications to serve the northeastern United States could not be evaluated until the Commission determined under the Ashbacker doctrine whether certain procedural steps needed to be taken to ensure all potential competitors their due process. Others were held up due to pending rate cases, settlement discussions or formal hearings which all had an effect on whether the application was in the public convenience and necessity. The attachments identify situations where these types of occurrences materially extended the preparation time of the EA during the FY88-FY90 period.

We have listed the 144 written or formal EAs prepared during this period. The staff also reviewed the environmental aspects of about 5,200 other certificate applications during this same period. However, these reviews did not involve a written or formal EA since they involved either categorical exclusions or non-federal action findings. We have shown the filing date of the applications as well as the date of completion of the EA. We have inserted a significant date column to identify situations where some event delayed actual processing of the EA. Finally, we have included a comments column describing the reasons for these delays. We have also listed other dockets that were involved in the preparation of the EA. Taking into consideration these delays, we computed an average processing time of 184 days for the 144 EAs involved in this study.

DOCKET NUMBER	DATE FILED	EVENT DATE	EA COMPLETED	ELAPSED TIME	COMMENTS
CP62-0205-001	04/09/90	/ /	01/17/91	283	
CP81-0296-015	07/18/88	04/15/89	01/23/90	283	APPLICATION INCOMPLETE. ENVIRONMENTAL REPORT WAS NOT FILED UNTIL 9 MONTHS LATER.
CP86-0704-000	10/30/87	02/22/88	01/31/89	344	PROCESSING COMMENCED UPON CERTIFICATION BY ALJ TO COMMISSION ON 2/22/88
CP87-0004-002	05/13/88	/ /	06/01/88	19	PENNEAST SALES PROJECT - OTHER DOCKETS INVOLVED IN EA INCLUDE: CP87-4-000, CP87-4-001, CP87-4-002, CP87-5-000, CP87-28-000, CP87-28-002.
CP87-0205-001	09/04/87	/ /	08/30/88	361	INDIANAPOLIS SERVICE PROJECT - ONTER DOCKET INVOLVED IN EA INCLUDES: CP87-205-000. TECHNICAL CONFERENCE HELD. REQUIRED DATA REQUESTS. INVOLVED NONJURISDICTIONAL FACILITIES.
CP87-0312-006	10/31/89	/ /	04/30/90	181	
CP87-0339-000	05/07/87	03/17/88	05/16/88	60	NORTHEAST PROJECT. DETERMINED DISCRETE BY COMMISSION ORDER MARCH, 1988.
CP87-0358-001	10/06/87	06/29/88	03/20/89	264	NORTHEAST PROJECT. NOREX PROJECT LEAD DOCKET OTHER DOCKET INCLUDED IN EA: CP87-428-001 INCOMPLETE APPLICATION. ENVIRONMENTAL REPORT FILED 8 MONTHS AFTER APPLICATION. APPLICATION AMENDED TWICE AFTER FILING. LAST AMENDMENT MADE 15 MONTHS AFTER ORIGINAL FILING. DETERMINED DISCRETE BY COMMISSION ORDER DATED 06/29/88.
CP87-0492-000	08/13/87	/ /	05/11/88	272	
CP88-0062-000	11/04/87	/ /	11/25/87	21	
CP88-0068-000	11/09/87	/ /	01/11/88	63	
CP88-0101-000	12/01/87	/ /	04/28/88	149	
CP88-0114-000	12/08/87	/ /	02/04/88	58	
CP88-0129-003	01/13/89	/ /	04/28/89	105	NEW JERSEY/PROVIDENCE PROJECT LEAD DOCKET OTHER DOCKETS INVOLVED IN THE EA INCLUDE: CP88-129-001, CP88-129-002, CP88-163-000, CP88-163-001, AND CP89-656-000
CP88-0141-000	12/21/87	/ /	01/27/88	37	
CP88-0147-000	12/30/87	/ /	04/17/88	109	
CP88-0160-000	01/11/88	/ /	02/23/88	43	
CP88-0161-000	01/11/88	/ /	02/23/88	43	
CP88-0164-000	01/14/88	/ /	08/30/88	229	
CP88-0167-000	01/15/88	/ /	07/27/88	194	
CP88-0171-001	07/28/89	/ /	01/30/90	186	TENCO PROJECT - OTHER DOCKETS INVOLVED IN THE EA INCLUDE: CP88-92-001, CP88-194-001, CP88-94-001.
CP88-0180-002	10/31/89	/ /	06/30/90	242	CDS PROJECT - OTHER DOCKET INVOLVED IN EA WAS: CP88-185-002.
CP88-0199-000	01/19/88	/ /	02/05/88	17	
CP88-0213-000	05/13/88	/ /	11/25/88	196	
CP88-0217-000	01/29/88	/ /	06/09/88	132	
CP88-0263-000	03/01/88	/ /	04/27/88	57	

CP88-03[illegible]-000	03/24/88	01/05/89	02/04/89	30	NEEDED ADDITIONAL INFORMATION. COMPLETE RESPONSE TO DATA REQUEST NOT FILED UNTIL JANUARY 1989. PROCESSING DELAYED DUE TO NORTHEAST OPEN SEASON PROCEEDING.
CP88-0313-000	03/25/88	/ /	09/19/88	178	
CP88-0368-000	04/29/88	/ /	06/09/88	41	
CP88-0375-000	05/04/88	/ /	12/09/88	219	
CP88-0382-000	05/06/88	/ /	10/18/88	165	
CP88-0387-000	05/03/88	/ /	07/15/88	73	
CP88-0413-000	05/26/88	/ /	08/03/88	69	
CP88-0415-000	05/26/88	/ /	08/23/88	89	
CP88-0416-000	05/26/88	/ /	08/01/88	67	
CP88-0420-000	05/27/88	/ /	01/27/89	245	
CP88-0463-000	06/13/88	/ /	08/05/88	53	
CP88-0464-000	06/13/88	/ /	12/07/88	177	
CP88-0464-000	06/13/88	/ /	12/07/88	177	
CP88-0477-000	06/20/88	/ /	11/02/88	135	
CP88-0482-000	06/20/88	/ /	03/08/89	261	
CP88-0530-000	07/28/88	/ /	10/15/88	79	
CP88-0541-000	07/01/88	/ /	05/22/89	325	APPLICANT DELAYED REPSONDING TO FORMAL DATA REQUEST.
CP88-0542-000	07/01/88	/ /	07/19/89	383	NEEDED ADDITIONAL INFORMATION. FORMAL DATA REQUEST PREPARED.
CP88-0555-000	07/08/88	/ /	01/30/89	206	
CP88-0683-000	08/15/88	/ /	04/30/90	623	LEAD DOCKET. RELATED TO DOCKET NO. CP88-821-000. NEEDED ADDITIONAL INFORMATION. APPLICANT DELAYED IN RESPONDING TO DATA REQUEST.
CP88-0692-000	08/18/88	/ /	11/09/88	83	
CP88-0695-000	08/18/88	/ /	11/10/88	84	
CP88-0698-000	08/19/88	/ /	10/27/88	69	
CP88-0708-000	08/22/88	/ /	08/20/89	363	CONFLICTED WITH NORTHEAST PROJECTS. APPLICANT MADE SEVERAL ROUTE REVISIONS.
CP88-0712-002	10/31/89	/ /	06/09/90	221	RELATED TO CP90-189-000.
CP88-0760-002	09/02/88	12/18/89	04/06/90	109	NUMBER OF AMENDMENTS FILED. LAST AMENDMENT FILED 12/18/89, MORE THAN A YEAR AFTER ORIGINAL APPLICATION.
CP88-0761-000	09/06/88	/ /	04/07/89	213	
CP88-0805-000	09/14/88	/ /	07/31/89	320	LACKED SUFFICIENT INFORMATION TO PROCESS APPLICATION. AWAITED FILINGS BY APPLICANT.
CP88-0833-000	09/26/88	/ /	08/04/89	312	NEEDED ADDITIONAL INFORMATION.
CP89-0003-000	10/03/88	/ /	04/14/89	193	
CP89-0006-000	10/03/88	/ /	04/01/89	180	APEC PROJECT LEAD DOCKET OTHER DOCKETS ANALYZED IN THE EA INCLUDED: CP87-5-001, CP87-5-002, CP87-5-003, CP87-554-001
CP89-0032-000	10/07/88	/ /	06/06/89	242	
CP89-0085-000	10/24/88	/ /	07/26/89	275	
CP89-0144-000	11/08/88	08/21/89	09/19/89	29	AWAITED FILING OF NOISE SURVEY BY APPLICANT.
CP89-0265-000	11/10/88	/ /	12/19/88	39	

CP89-0267-000	11/22/88	/ /	11/07/89	350	CULTURAL RESOURCE CONCERNS. STAFF HAD TO CONSULT WITH ADVISORY COUNCIL ON HISTORIC PRESERVATION AND THE APPLICANT REFUSED TO COMPLY WITH CULTURAL RESOURCE MITIGATION PLAN.
CP89-0274-000	11/22/88	/ /	05/03/89	162	
CP89-0275-000	11/22/88	/ /	05/04/89	163	
CP89-0333-000	12/05/88	/ /	09/21/89	290	
CP89-0453-000	12/19/88	/ /	09/25/89	280	
CP89-0465-000	12/21/88	/ /	03/15/89	84	
CP89-0515-000	12/30/88	/ /	04/25/89	116	
CP89-0524-000	12/20/88	/ /	06/29/89	191	
CP89-0576-000	01/10/89	/ /	09/19/89	252	
CP89-0576-001	02/05/90	/ /	03/08/90	31	
CP89-0594-000	01/11/89	/ /	05/04/89	113	
CP89-0636-000	01/17/89	/ /	09/29/89	255	
CP89-0655-000	01/18/89	/ /	08/25/89	219	
CP89-0661-001	02/28/90	/ /	05/01/90	62	EAGLE POINT/NEP PROJECT - OTHER DOCKETS IN THE EA INCLUDED: CP89-635-000, CP89-635-001, CP89-661-000 AND CP89-637-000. PROCESSING COMMENCED UPON FILING OF THIS DOCKET.
CP89-0783-000	02/08/89	/ /	07/12/89	154	
CP89-0802-000	02/10/89	/ /	04/06/89	55	
CP89-0877-000	02/21/89	/ /	08/08/90	533	LAKCED SUFFICIENT INFORMATION TO PROCESS APPLICATION.
CP89-0880-000	02/22/89	/ /	12/19/89	300	APPLICATION WAS PROTESTED. REQUIRED ADDITIONAL SURVEYS FROM SHPO AND FWS AND STATE CLEARANCES.
CP89-0889-000	02/23/89	/ /	06/19/90	481	PCB CONCERNS. REQUIRED CONSULTATION WITH EPA.
CP89-0930-000	03/01/89	/ /	05/23/89	83	
CP89-0959-000	03/08/89	/ /	03/28/89	20	
CP89-0983-000	03/10/89	/ /	06/29/89	111	
CP89-1024-000	03/17/89	10/30/89	01/24/90	86	ADDITIONAL INFORMATION REQUIRED. APPLICANT DELAYED IN RESPONSE TO STAFF DATA REQUESTS. COMPLETE RESPONSE NOT RECEIVED UNTIL 10/30/89.
CP89-1126-000	03/31/89	/ /	07/13/89	104	
CP89-1223-000	04/17/89	/ /	06/15/90	424	ADDITIONAL INFORMATION REQUIRED. PREPARED FORMAL DATA REQUEST.
CP89-1265-000	04/24/89	/ /	09/29/89	158	
CP89-1276-000	04/27/89	/ /	08/18/89	113	
CP89-1337-000	05/08/89	/ /	12/20/89	226	
CP89-1340-000	05/08/89	/ /	10/17/89	162	
CP89-1343-000	05/09/89	/ /	03/16/90	311	APPLICANT DELAYED IN RESPONDING TO DATA REQUEST.
CP89-1474-000	05/22/89	/ /	09/04/89	105	
CP89-1475-000	05/22/89	/ /	12/20/89	212	
CP89-1475-000	05/24/89	/ /	10/21/89	150	
CP89-1487-000	05/22/89	/ /	10/24/89	155	
CP89-1502-000	05/24/89	/ /	10/21/89	150	
CP89-1525-000	05/26/89	/ /	08/23/90	454	CONFLICTED WITH PROCESSING OF NORTHEAST AND MOBILE BAY PROJECTS.
CP89-1526-000	05/26/89	/ /	08/11/89	77	
CP89-1540-000	05/30/89	/ /	08/20/90	447	NEEDED ADDITIONAL INFORMATION.

DOCKET NUMBER	FILED	DATE	COMPLETED	TIME	COMMENTS
CP89-1581-000	06/07/89	/ /	02/06/90	244	
CP89-1612-000	06/13/89	/ /	06/27/90	379	PCB PROBLEM. AWAITED EPA REVIEW.
CP89-1628-000	06/14/89	/ /	02/16/90	247	
CP89-1674-000	06/22/89	/ /	06/26/90	369	LACKED SUFFICIENT INFORMATION TO PROCESS.
CP89-1680-000	06/22/89	/ /	10/23/89	123	
CP89-1731-000	07/03/89	/ /	03/16/90	256	
CP89-1739-000	07/07/89	/ /	04/30/90	297	
CP89-1742-000	07/07/89	/ /	06/18/90	346	LACKED SUFFICIENT INFORMATION TO PROCESS.
CP89-1761-000	07/10/89	/ /	06/21/90	346	PCB PROBLEM. AWAITED EPA REVIEW.
CP89-1864-000	07/25/89	/ /	12/22/89	150	
CP89-1873-000	07/28/89	/ /	07/18/90	355	LACKED SUFFICIENT INFORMATION TO PROCESS.
CP89-1929-000	08/08/89	/ /	05/11/90	276	
CP89-1983-000	08/22/89	/ /	06/29/90	311	PCB CONCERNS. AWAITED EPA REVIEW.
CP89-2049-000	09/02/89	/ /	06/20/90	291	
CP89-2081-000	08/12/89	03/30/90	06/22/90	84	APPLICATION WAS DEFICIENT. APPLICANT DELAYED IN RESPONDING TO DATA REQUEST. ROUTE WAS MODIFIED BY THE APPLICANT AFTER THE APPLICATION WAS FILED.
CP89-2171-000	09/27/89	/ /	04/18/90	203	
CP90-0041-000	10/10/89	/ /	01/01/90	83	MOJAVE-KERN RIVER-WYCAL PIPELINE PROJECT - LEAD DOCKET OTHER DOCKETS IN THE EA INCLUDED: CP85-437 et.al., CP87-479-001, CP87-480-000, CP89-1-002, AND CP89-2048-000
CP90-0051-000	10/12/89	/ /	12/21/89	70	
CP90-0086-000	10/20/89	/ /	04/03/90	165	
CP90-0138-000	10/27/89	/ /	10/19/90	357	
CP90-0139-000	10/27/89	/ /	06/19/90	235	
CP90-0141-000	10/27/89	/ /	04/30/90	185	
CP90-0163-000	10/30/89	/ /	06/08/90	221	
CP90-0239-000	11/13/89	/ /	06/21/90	220	
CP90-0387-000	12/14/89	/ /	08/31/90	260	
CP90-0521-000	01/16/90	/ /	06/20/90	155	
CP90-0643-000	01/26/90	/ /	08/23/90	209	
CP90-0644-000	01/29/90	/ /	10/04/90	248	
CP90-0677-000	02/01/90	/ /	09/01/90	212	
CP90-0685-000	02/01/90	/ /	08/01/90	181	STEUBEN PROJECT, LEAD DOCKET. OTHER DOCKETS ANALYZED IN THE EA INCLUDED: CP89-1686-000 AND CP90-177-000.
CP90-0738-000	02/08/90	/ /	08/21/90	194	
CP90-0909-000	03/05/90	/ /	09/15/90	194	
CP90-0959-000	03/12/90	/ /	05/11/90	60	
CP90-1251-000	04/26/90	/ /	06/30/90	65	
CP90-1297-000	05/01/90	/ /	11/08/90	191	
CP90-1323-000	05/08/90	/ /	06/29/90	52	
CP90-1346-000	05/11/90	/ /	11/05/90	178	
CP90-1512-000	06/11/90	/ /	08/01/90	51	
CP90-1608-000	06/22/90	/ /	08/10/90	49	
CP90-1735-000	07/13/90	/ /	09/27/90	76	
CP90-1847-000	07/30/90	/ /	09/25/90	57	
CP90-1848-000	07/30/90	/ /	09/21/90	53	
CP90-1865-000	08/01/90	/ /	10/03/90	63	
CP90-1961-000	08/09/90	/ /	12/21/90	134	
CP90-2060-000	08/23/90	/ /	10/12/90	50	

COUNT OF CASES: 144 AVERAGE PROCESSING TIME: 184

March 12, 1991

Memorandum To: Chuck Wilson, GAO

From : William H. Marmura, OPPR WHM
FERC

Subject : Preparation of Environmental Impact Statements

The attached study is responsive to your request relative to the preparation of environmental impact statements for FY88 - FY90 by the Office of Pipeline and Producer Regulation.

This report discusses the preparation of draft and final environmental impact statements (DEIS or FEIS) completed during FY88 through FY90 by the Office of Pipeline and Producer Regulation (OPPR) within the FERC. GAO asked for this information in order to evaluate the length of time it has taken the Commission to prepare environmental impact statements. Excluded from this evaluation, at GAO's request, were cases where the Commission's environmental review did not produce a written DEIS and/or FEIS.

Six DEISs and five FEISs have been prepared by OPPR during the subject time period. One of the projects, the Champlain Pipeline Project, was placed on hold by the applicant after a DEIS had been prepared and released to the public.

As previously discussed in the February 15, 1991 study entitled, Preparation of Environmental Assessments, similar procedural steps occur whereby the application(s) are distributed, reviewed for completeness, and deficiency letters (incomplete applications) or data requests (for missing data) are prepared. Most of these major cases were also subject to the need to wait for the filing of related applications, the Ashbacker doctrine, and other procedural activities that occurred during their processing. (We have attached a list of the relevant Commission orders in appendix A that may be obtained from us for your review if you wish to examine a project's entire procedural background.)

We have listed the DEISs and FEISs prepared by OPPR in table 1. We have shown the filing date of a lead docket for each project. We have also inserted an amendment date column to identify a major filing event that delayed the actual start-up of processing of the environmental impact statement. OPPR required an average of 300 days (10 months) to prepare the DEISs and an additional 162 days (5.4 months) to complete the FEISs. An average total processing time of 462 days (15.4 months) was required to complete the environmental impact statements involved in this study. (See table 2.)

Table 1

EIS PREPARED BY OPPR

PROJECT NAME	LEAD DOCKET	FILING DATE	AMENDMENT DATE	SCOPING NOTICE DATE	DEIS DATE	FEIS DATE
Mojave-Kern River (EOR)	CP85-437-003	4/15/85	11/22/85 a/	8/23/85	1/23/87	12/18/87
Wycal EIS Supplement	CP87-480-000	8/4/87	-	12/14/87	7/25/88	10/3/88
Ocean State Power Project	CP87-131-001	12/18/86	8/5/87	8/19/87	3/4/88	7/8/88
Champlain Pipeline Project	CP88-846-000	1/17/89	-	2/17/89	11/6/89	NONE
Iroquois/Tennessee Phase I Pipeline Project	CP89-634-001	1/17/89	-	2/17/89	11/13/89	6/1/90
Niagara Import Point Project	CP88-171-001	1/15/88	7/28/89	10/13/89	3/16/90	6/15/90

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a/ Transwestern Pipeline Company filed Docket No. CP86-212-000 with 358 miles of related pipeline facilities.

Table 2

MONTHS REQUIRED TO PREPARE ENVIRONMENTAL IMPACT STATEMENTS

PROJECT NAME	DEIS	FEIS
Mojave-Kern River1/	14.0	10.9
Wycal EIS Supplement2/	11.7	2.3
Ocean State Power Project	7.0	4.1
Champlain Pipeline Project3/	9.7	-
Iroquois/Tennessee Phase I Pipeline Project	9.9	6.6
Niagara Import Point Project	7.7	3.0
Average	10.0	5.4

1/ Evaluated three major projects--Kern River, Mojave, and El Dorado and other alternatives. Preparation of EIS conducted jointly with the California State Lands Commission.

2/ Adopted major portions of Mojave-Kern River FEIS.

3/ Applicant requested that the Commission put the proposed project on hold after the DEIS was issued.

APPENDIX A

COMMISSION ORDERS

Mojave-Kern River and Wycal Projects

1. Initial Decision on Environmental Issues issued October 25, 1988, Docket Nos. CP85-437-000, *et al*.
2. Opinion Affirming Initial Decision on Environmental Issues and Making Supplemental Findings issued January 13, 1989, Docket Nos. CP85-437-000, *et al*.
3. Order Issuing Certificates issued May 8, 1989, Docket Nos. CP89-1-000, *et al*. (Mojave Pipeline Company)
4. Order Issuing Certificates, Granting and Denying Rehearing, and Clarifying and Modifying Prior Order issued January 24, 1990, Docket Nos. CP89-1-001, *et al*.
5. Order Issuing Certificate and Amending Prior Orders issued January 24, 1990, Docket Nos. CP90-41-000, *et al*. (Wyoming-California Pipeline Company)

Ocean State Power

1. Order Issuing Certificates issued October 3, 1988, Docket Nos. CP87-131-000, *et al*.

Champlain Pipeline Project

1. Applicant requested that project be put on hold indefinitely on November 7, 1989.

Iroquois /Tennessee Phase I Pipeline Project

1. Order Making Preliminary Determinations and Establishing Procedures issued July 30, 1990, Docket No. CP89-634-000, *et al*.
2. Opinion and Order Issuing Certificates, Issuing Presidential Permit, Dismissing Application, Issuing Blanket Certificates, Denying Petition for Declaratory Order, Authorizing Abandonment, Granting in Part and Denying in Part Rehearing and Modifying Prior Order issued November 14, 1990, Docket No. CP89-634-000, *et al*.

Niagara Import Point Project

1. Order Issuing Certificates, Issuing Presidential Permit, Authorizing Abandonment, Dismissing Dockets, and Clarifying Prior Order issued September 13, 1990, Docket Nos. CP88-171-000, *et al*.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 6B: Why does FERC not adopt the guidelines of the Council on Environmental Quality on National Environmental Policy Act compliance?

Answer: The Commission's regulations in 18 CFR Part 380 implement the requirements of the National Environmental Policy Act of 1969. Section 380.1, which describes the purpose of those regulations, sets forth the Commission's policy with regard to the regulations of the Council on Environmental Quality (CEQ). Specifically, section 380.1 states that "[t]hese regulations supplement the regulations of the Council on Environmental Quality, 40 CFR Parts 1500 through 1508 (1986)" and that "[t]he Commission will comply with the regulations of the Council on Environmental Quality except where those regulations are inconsistent with the statutory requirements of the Commission." Thus, the Commission has in effect adopted the CEQ regulations.

We are aware of no requirement that the Commission, or any other Federal agency, take some further step to formally adopt these regulations. The CEQ regulations provide that "Parts 1500 through 1508 of this title provide regulations applicable to and binding on all Federal agencies for implementing the procedural provisions of [NEPA] except where compliance would be inconsistent with other statutory requirements." In this regard, we would note that in the rulemaking which culminated in Part 380, the Commission actually incorporated the CEQ regulations into its proposed rules, but was told by the CEQ that specific agency rules are meant to supplement CEQ regulations by focusing on the requirements that are particular to each agency, rather than repeat or paraphrase CEQ's general regulations that speak to all Federal agencies.

QUESTIONS FOR THE RECORD FROM SENATOR WIRTH

Question 6C: In your testimony, you refer to "the delays built into the current statutory scheme". Would you please elaborate on statutory problems you would like to change?

Answer: Since satisfying National Environment Policy Act (NEPA) requirements is most often the delaying factor in certificate proceedings, the regulatory process should be expedited by S. 341's provisions making the Commission the "sole agency" responsible for preparing environmental impact statements (EIS), coordinating the efforts of all resource agencies for all projects arising under the Natural Gas Act and the Federal Power Act, and allowing the Commission to charge applicants for environmental work performed by private-sector firms.

Also, if this "lead agency" proposal is to expedite the review process, it should be made clear that the Commission can enforce reasonable deadlines for other agencies to complete their environmental review. In particular, the act should make clear that the Commission is authorized to take appropriate steps and to perform necessary activities to ensure that all NEPA-related reviews are completed in a timely manner.

S. 341's proposed modifications to section 311 of the Natural Gas Policy Act also are important, since explicit authorization for pipelines to transport gas "on behalf of any person" should promote greater competition and the Commission's open access policy. The bill's explicit statutory recognition of section 311 construction authorization also would be helpful to eliminate any possible uncertainty concerning the existence of such authority.

The regulatory process also would be improved by S. 341's proposal to increase, from 30 to 60 days, the notice required to be given by pipelines of changes in their rates and other tariff provisions. These filings often involve complex issues. Currently, if the Commission is unable to complete its review within thirty days, the effective dates of rate changes and other tariff revisions generally are suspended for up to five months. Therefore, an additional thirty days for review should make the regulatory process more efficient, allowing the Commission to resolve important rate issues at an earlier time.

QUESTIONS FOR THE RECORD FROM SENATOR WALLOP

Question 1: As proposed in the National Energy Strategy the deregulation of existing interstate pipelines is to be contingent on two preconditions: first, that a pipeline provides comparable service to third-party shippers, and second that a pipeline does not have market power in either the producing field or in the selling market.

However, it appears that the section 205 non-jurisdictional option could be used to remove an existing pipeline from federal regulation through "acquisition" even if the preconditions are not met (new NGA section 7(k)(1)). Is that correct?

Answer: As it is currently worded, the nonjurisdictional option set forth in section 205 of S. 570 would allow a pipeline to "acquire" a facility for, and engage in, the transportation or sale of natural gas through that facility without a certificate issued by the Commission.

Neither the text of the proposed legislation nor the sectional analysis sheds any further light on this matter. Thus, it would appear that the nonjurisdictional option could be used to remove an existing pipeline from Federal jurisdiction without the exercise of Federal oversight. On the other hand, a jurisdictional pipeline may not terminate certificated services or abandon certificated facilities without first obtaining approval of the Commission under Natural Gas Act section 7(b). The supplemental testimony which the Commission is filing simultaneously with the responses to the follow-up questions raises this concern.

QUESTIONS FOR THE RECORD FROM SENATOR WALLOP

Question 2: What are S. 570's preconditions for non-regulation of new pipelines?

Answer: The preconditions for the nonjurisdictional option are set forth in section 205 of S. 570. This section provides that if a person elects to construct, extend, acquire, or operate a facility for the transportation or sale of natural gas and engage in the transportation or sale of natural gas through that facility without a certificate, then that person (1) is not a natural gas company for purposes of the Natural Gas Act and (2) shall not participate in any proceeding under the Natural Gas Act to consider an application for a certificate for the construction or extension of competing facilities. It also provides that the construction or extension of a facility under this option may be subject to regulation by a State; however, rates or charges for the transportation or sale of natural gas by means of such a facility or extension are not subject to State regulation, except to the extent that facility or extension is engaged solely in Natural Gas Act section 1(c) activities. No other preconditions exist.

QUESTIONS FOR THE RECORD FROM SENATOR WALLOP

Question 3: For both new pipelines that are exempted from regulation and existing pipelines which are deregulated, what protections and remedies against discrimination and unfair practices would producers have under S. 570?

Answer: Nonjurisdictional Option. If a person elects to proceed under the proposed nonjurisdictional option presented in section 205(a), the Commission would appear to have no authority over that person as to its interactions with producers or other entities. Certainly, no such direct authority is conveyed by the terms of section 205, and since the Commission appears to have no authority over the rates, terms, and conditions of activities conducted pursuant to this authorization, no other basis for regulating the relationship between producers and pipelines would appear to exist. However, as discussed below, it is unclear what authority proposed section 7(j) confers upon the Commission with respect to facilities constructed under this option. This matter is discussed further under the optional certificate procedure below.

Rate Deregulation. Proposed section 205(b) in essence allows the Commission to deregulate rates of natural gas companies (i.e., order that they are not subject to the jurisdiction of the Commission) under section 4 of the Natural Gas Act upon finding that the market the natural gas company is authorized to serve is competitive and that the transportation or sales services are offered in that market on a not unduly discriminatory basis. Thus, this proposal would appear to offer certain protections to producers in the sense that the Commission must first make a finding that sufficient competition exists and that no undue discrimination exists with regard to transportation and sales service before removing a pipeline from jurisdiction.

Optional Certificate Procedure. The proposed optional certificate procedure provides that if the Commission, after a hearing upon the petition of a person who has made a bona fide offer to enter into a contract, finds that the failure to provide a requested rate, charge, classification, or practice in connection with the transportation of natural gas through facilities constructed, extended, acquired, or operated under a certificate issued under either proposed section 7(i) (the optional certificate procedure) or proposed section 7(k) (the nonjurisdictional option) is unduly discriminatory, it shall determine rates, charges, classifications, or practices which are not unduly discriminatory and fix the same.

One matter that remains unclear with regard to this discussion, however, is the statement above that the undue discrimination standard would apply to certificates issued under proposed section 7(k) (the proposed nonjurisdictional option), as well as to those issued under proposed section 7(i) (the optional certificate). The problem is that no certificate is issued under proposed section 7(k); in fact, the entire thrust of that proposal is to eliminate the certificate procedure, and thus Commission jurisdiction over such facilities and activities. Further, unlike the optional certificate procedure, the nonjurisdictional option does not provide for filing a petition to contest the terms and conditions of service as unduly discriminatory. On this basis, it would seem that the protection against undue discrimination set forth in section 204 would not apply to the nonjurisdictional option, but this matter needs further clarification.

QUESTIONS FOR THE RECORD FROM SENATOR WALLOP

Question 4: Section 213 of S. 570 gives the President the authority to "waive any law" relating to the importation of natural gas if it is in the national interest. What would this provide that is not contained in Title III of the Natural Gas Policy Act?

Answer: Basically, Title III of the Natural Gas Policy Act (NGPA) is intended to deal with emergency shortages of natural gas. The authority granted in subsection (c) of section 213 (S. 570) appears to be broader in scope. The President's authority in Title III of the NGPA is limited to "natural gas supply emergencies." Thus, the President must first find that (1) there is a severe natural gas shortage, endangering the supply of natural gas for high-priority uses, and (2) that other alternatives to the exercise of his authority under Title III have been exhausted to the maximum extent possible before he can exercise the Title III authority. Section 213 of S. 570, on the other hand, only requires that the President find that the importation or exportation of natural gas "is in the national interest." There are also 120 day time limitations (which can be extended) on the President's authority in Title III of the NGPA. The proposed Section 213 authority does not contain simiiliar limitations.

Under Title III of the NGPA, having declared a "natural gas supply emergency," the President is limited to (1) authorizing the purchase of natural gas and requiring pipelines to transport it, and (2) allocating available supplies of natural gas. Under proposed section 213, the President can waive any law relating to the importation of natural gas. Since section 213 proposes to remove the need for any governmental approvals of the act of importing or exporting natural gas, this provision presumably authorizes the President to waive any environmental or other preconstruction requirements related to the importation.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 1: Has the Commission's open access transportation program advanced to the point such that pipelines no longer have market power either at the delivery point, the producing field, or in the transportation of gas?

Answer: Although the Commission's open access program has made great strides, it has not yet reached the point where the Commission can conclude that interstate pipelines, in general, lack significant market power in the resale of gas at the delivery point or in the purchase of gas in supply areas. Currently, the Commission is addressing these questions on a case-by-case basis. These field and delivery point issues are addressed, for example, when a pipeline applies for a gas inventory charge (GIC) certificate. The Commission, after analyzing market data, has found workable competition in the field and delivery markets of two pipelines, and has issued GIC certificates. However, to date, the Commission has conducted its market power analysis on a case by case basis. The Commission also may consider a generic rule covering this issue in the near future.

The focus of FERC's competitive analyses for natural gas pipelines has been on the resale of natural gas ("the merchant function") and not on whether there is workable competition in the transportation of the gas to market ("the transportation function"). The question here is whether customers have effective alternatives to buying gas from the pipeline. The Commission examines whether the pipeline's transportation of third party gas is reasonably comparable to the transportation service embedded in the pipeline's bundled sales service, whether the transportation gives customers access to wellhead markets on competitive terms and whether there is competitive third party gas supply available. Thus, a market which is served by only one pipeline may be competitive for the merchant function, but not for the transportation function. The Commission has yet to consider the extent of competition in the transportation function for natural gas pipelines.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 2: If sections 203, 204 and 205 of S. 570 were adopted how would that affect the Commission's open access transportation?

Answer: Sections 203, 204, and 205 of S. 570 each raise several important questions regarding the nature of the Commission's continuing regulatory responsibilities. It is difficult to assess fully how these provisions, if enacted, would affect the open access program. However, several elements of these proposals seeks to remove unwarranted statutory barriers to greater competition and merit serious consideration.

QUESTION FOR THE RECORD FROM SENATOR DOMENICI

The National Energy Strategy report indicates that comparable third party transportation and competitive markets are necessary prerequisites to the deregulation of pipelines.

Question 3(a): Does S. 570 require those two prerequisites to be met before an existing pipeline is deregulated?

Answer: To the extent deregulation would occur under proposed section 205(g), the Commission must make these findings. Proposed section 4(g) of the Natural Gas Act provides that a hearing may be held "upon the application of a natural gas company" to determine comparability and competitive markets. This suggests that the provision would apply to pipeline companies operating as natural gas companies prior to their application under proposed section 4(g) seeking to deregulate the rates and charges made, demanded or received for or in connection with the transportation or sale of natural gas in a given market. This language would seem to enable only an existing "natural gas company" to seek deregulation under this authority. Also, it should be noted generally that the intent of proposed section 4(g) is to deregulate rates and charges in connection with sales or transportation in a given market.

Question 3(b): Would they be required if a new pipeline is to be not regulated?

Answer: Section 205 of S. 570 does not specify directly whether the comparability and competitive markets prerequisites would be applicable if a new pipeline will not be regulated.

Question 3(c): Proposed Natural Gas Act section 7(k)(1) appears to allow the deregulation of an existing pipeline through acquisition but does not appear to require the two NES prerequisites. Is that correct?

Answer: Proposed section 7(k)(1) does not incorporate directly the two prerequisites, comparability of service and competitive markets, into its provisions.

Question 3(d): If a pipeline were exempted from regulation, how could the Commission or the Department ensure the NES preconditions of comparable third party transportation and competitive markets would continue to exist following deregulation?

Answer: In order to ensure that the NES preconditions would continue to exist following deregulation, the Commission could devise some form of monitoring program or impose reporting requirements to see if circumstances have changed. In addition, or alternatively, the Commission could rely on complaints from participants in the market to ensure that a pipeline is providing transportation services comparable to its sales service and that the markets it services are still competitive.

Question 3(e): What would prevent a deregulated pipeline from discriminating against, or even excluding entirely, an independent producer, and what remedy would that producer have?

Answer: The thrust of the nonjurisdictional option proposed in section 205 appears to be to remove completely from the purview of the Commission all activities taking place under that option. As such, the Commission would seem to have no authority over persons proceeding under this option with regard to their interactions with producers or other entities. No direct authority is conveyed by the terms of section 205. Likewise, the Commission appears to have no authority over the rates, terms, and conditions of activities conducted under the nonjurisdictional option which allow it to regulate the relationship between producers and pipelines.

However, section 204 sets forth a procedure by which the Commission may determine if rates, charges, classifications, or practices are unduly discriminatory and fix those which are not. This authority is purported to extend to certificates issued under either the optional certificate procedure or the nonjurisdictional option. The problem is that no certificate is issued under the proposed nonjurisdictional option; in fact, the entire thrust of that proposal is to eliminate the certificate process, and thus Commission jurisdiction over such activities. On this basis, it would be difficult to apply the provision in section 204 conveying to the Commission the power to regulate undue discrimination to section 205 nonjurisdictional activities. This matter needs further clarification however in light of the problems noted above. (See Question 3 of Senator Wallop).

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 4 : Is there a factual basis to find that the market for gas at the border crossings with Canada and at the tailgates of LNG gasification plants are competitive? In view of the commanding role played by TransCanada Pipelines Ltd, and its marketing affiliate, how could such a finding be made?

Answer: With respect to the market for gas at border crossings with Canada, any factual findings are made by the Department of Energy (DOE). The Commission does not have the authority under Section 3 of the Natural Gas Act to approve natural gas imports by interstate pipelines in the first instance, nor imports by any other "person", which includes intrastate pipelines, local distribution companies, or industrial end-users. That authority resides solely in the DOE, which relies on its 1984 policy guidelines stating that any negotiated import contract/price is presumed to be competitive. DOE uses this policy to evaluate long-term import contracts, but DOE grants two-year blanket import authority without requiring any contracts to be filed by applicants.

The Commission has also issued certificates allowing marketers of imported gas to make sales for resale in interstate commerce at market-based rates. Salmon Resources Ltd., et al., 50 FERC ¶ 61,101 (1990). The Commission's determination, following the DOE import authorization, was based on the similarity between U.S. producers and marketers of Canadian (as well as U.S.) gas.

With respect to LNG gasification plants, the Commission has made findings of fact that the market was competitive in two cases. The Commission acted under its authority in Pan National Gas Sales Company and found that based on the record in that case, the sale for resale of imported LNG would be competitive without further regulatory qualifications. The facts of the case were that the LNG plant was located in a natural gas supply region (Louisiana) which contained many competitive natural gas sellers. Further, the historic users of the LNG plant, through which the LNG would be imported, would not pay any costs associated with these particular LNG sales. These historic users are currently paying a minimum bill established by the Commission to guarantee financing for the LNG plant, which would otherwise be non-operational at this time. (49 FERC ¶ 61,199 (1989).

The Commission acted under its authority in Distrigas/DOMAC, 45 FERC ¶ 61,428 (1988), and found that based on the facts in that case, the sale for resale of imported LNG would not be competitive without further regulatory qualifications. The Commission required a "cap" on the resale price of the LNG because the LNG plant was in a natural gas market area (Northeast U.S.) and natural gas demand in that market area exceeded supply.

With respect to the rate of TransCanada and its marketing affiliate, DOE grants import authorizations based on its review of the underlying contracts, and follows its 1984 guidelines which provide that any negotiated import contract/price is presumed to be competitive. We do not believe that DOE examines the role of Canadian pipelines and their affiliates.

As indicated above, the Commission has allowed a market-based rate for marketers, such as Salmon Resources, because marketers of Canadian (or domestic gas) function in the same way as domestic producers. Likewise, the Commission has not looked behind the contracts between the Canadian sellers and the domestic marketers/buyers to examine, for example, the role of an upstream Canadian pipeline. To do so might lead to the Commission being asked to look behind domestic producer/seller and buyer contracts, which would inject the Commission into wellhead transactions contrary to the Natural Gas Decontrol Act of 1989.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 5: Assume that a U.S. pipeline transporting Canadian gas to the U.S. market is providing open access transportation. Also assume that competing U.S. pipelines to the same market are not offering open access transportation.

Question 5(a): If the pipeline which is offering open access transportation applies for decontrol pursuant to proposed section 4(g) of the Natural Gas Act, would the fact that other competing pipelines serving this same market are not offering open access transportation be a factor in determining whether the pipeline should be exempted from regulations? Would that factor alone be sufficient to deny the 4(g) deregulation application?

Answer: The fact that competing pipelines are not offering open access service in the applicant pipeline's service market would be a factor in determining whether that market is competitive and therefore whether certain services of the pipeline should be exempted from regulation. This is because the absence of open access service on competing pipelines would limit the number of gas merchants in the service market. We note, however, that all major U.S. pipelines provide open access transportation.

Question 5(b): Who would have the burden of proof in a sec. 4(g) proceeding?

Answer: The pipeline applicant in a Natural Gas Act section 4(g) proceeding would have the burden of proving that its service market is competitive and that its transportation and sales services are comparable.

Question 5(c): Would a state commission be preempted from reviewing the purchases made by a local distribution company from a pipeline deregulated pursuant to section 4(g)?

Answer: At present, a State commission may not examine a Commission-approved rate for reasonableness because the Commission has exclusive jurisdiction under the Natural Gas Act over interstate pipeline transportation and wholesale rates. Also, a State cannot affect the wellhead prices of natural gas because the Natural Gas Policy Act deems deregulated wellhead prices to be just and reasonable under the Natural Gas Act. Under current law, however, a State commission may examine the prudence of a local distribution company's purchases from a particular source as opposed to other sources. While proposed section 4(g) of the Natural Gas Act removes the pipeline's transportation and wholesale rates from Commission jurisdiction upon certain findings, it is not clear whether a State commission would be preempted because section 4(g) does not deem the unregulated rates to be just and reasonable as does the Natural Gas Policy Act. As a result, the Federal preemption of State regulation that exists under the Natural Gas Act and Natural Gas Policy Act may be removed by this provision. On the other hand, courts may still hold that State regulation would continue to be preempted if they found that Congress intended for Federal regulation to occupy the entire field of interstate transportation and wholesale rates, or because State intrusion would stand as an obstacle to Congress' deregulation objective. Thus, whether a State commission would be preempted would depend upon the statutory scheme established by Congress. Moreover, given the litigation then developed with respect to similar issues following termination of oil price controls during the 1980's, we recommend the legislation be as specific as possible on Federal/ State jurisdictional questions.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 6: Section 212 of S. 570 would appear to define "importation" to include all "actions involved in bringing natural gas into the United States." Would this include sales and transportation downstream from the border?

Answer: The bill would remove the regulatory oversight granted to FERC and the Department of Energy's (DOE) Office of Fossil Energy through DOE delegation orders pursuant to the Department of Energy Organization Act. Accordingly, there would be no review or regulation of competitiveness or need for the imported gas, or construction of facilities generally outside the Commission's Natural Gas Act jurisdiction required to implement importation of gas. However, the sectional analysis accompanying the bill emphasizes that imported gas would be treated in the same manner as domestic production, i.e., there would be no regulation of the gas until the gas enters a domestic pipeline system. At that point, it can be argued the transportation and/or sales of the gas would be regulated pursuant to the jurisdiction granted under the Natural Gas Act and Natural Gas Policy Act.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 7: Suppose that gas sold at the border in a first sale is resold by a marketer. Would that resale also be exempted from Natural Gas Act jurisdiction under the proposed Natural Gas Act section 3(a)?

Answer: Yes. Since proposed Natural Gas Act section 3(a) provides that importation of gas would be considered a first sale that appears to be covered by Natural Gas Policy Act secticn 601 (a)(1)(A), sales of imported gas made by a marketer would be exempt from Natural Gas Act jurisdiction.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 8: Under proposed Natural Gas Act section 3(b), would FERC retain the jurisdiction to "level the playing field" regarding differences in rate design between U.S. and Canadian gas?

Answer: Under proposed Natural Gas Act section 3(b), the Commission would retain jurisdiction to "level the playing field" to the extent the rates, charges, and practices at issue fall under its NGA jurisdiction.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 9: Could proposed Natural Gas Act section 3(c) or 3(d) be used to overturn or preempt the U.S. - Canada Free Trade Agreement?

Answer: Generally speaking, if a treaty and a Federal statute are incompatible, an attempt must be made to interpret them in such a manner that the inconsistency is resolved. If there is no way to resolve the inconsistency, the "later-in-time" rule applies. For example, an incompatible subsequent Federal statute is superior to a previous treaty. However, the general principle is that "an Act of Congress ought never to be construed to violate the law of nations, if any other possible construction remains ...." Murray v. Schooner Charming Betsy, 6 U.S. (2Cranch) 64, 118 (1804)(Marshall, C.J.). As discussed in our supplemental testimony, this matter should be clarified.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 10: Could proposed Natural Gas Act section 3(d) be used to overturn FERC Opinion No. 256?

Answer: It does not appear that proposed Natural Gas Act section 3(d) is intended to be used to overturn FERC Opinion No. 256. That opinion establishes the Commission's policy for how U.S. pipelines should pass through to sales customers the costs of imported gas once that gas enters the United States. In other words, it does not involve the actual importation. By its provisions, proposed section 3(d) of the Natural Gas Act would permit the President to waive, or establish an expedited timetable for compliance with, provisions of law relating to the exportation or importation of natural gas. Its stated purpose is to ensure that if the President finds a significant exportation or importation project important to the national interest, the project would not be delayed unnecessarily. Therefore, proposed section 3(d) appears to be aimed only at the arrangements for export or import, not at the specific rate treatment of gas supplies that are exported or imported under those arrangements. However, this analysis could change depending on how broadly or narrowly the phrase "provisions of law relating to" gas imports or exports would be construed and interpreted.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 11: Regarding domestic first sale under the NGPA, FERC has interpreted the guaranteed passthrough provision as entitling the purchaser the opportunity to try to recover costs in commodity rates and not necessarily the guarantee of "as billed" treatment. Could proposed section 3(b) be used to give imported gas a regulatory advantage over domestic gas?

Answer: Proposed section 3(b) of the Natural Gas Act could not be used to give imported gas a regulatory advantage over domestic gas (except to the extent that until January 1, 1993 some domestic gas is still subject to Natural Gas Act certificate requirements and Natural Gas Policy Act maximum lawful prices). Proposed section 3(b) is intended to serve to ensure uniform regulatory treatment of domestic and imported gas supplies. Accordingly, while the Commission under proposed section 3(a) could not in any way affect the price charged a purchaser for the importation of gas, it still could, in the exercise of its Natural Gas Act sections 4 and 5 authority, determine the way in which a domestic pipeline recovered the costs for imported gas in its resale rates to its customers. However, proposed section 3(b) would require that the Commission, in determining how a domestic purchaser should be allowed to recover the costs of imported gas, ensure that imported gas is treated no differently from domestic gas.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 12: To the extent that gas to be exported is commingled with gas consumed in the United States prior to export, would proposed section 3(b) prohibit FERC from imposing conditions on the commingled stream even if the same conditions apply to the domestically consumed gas?

Answer: According to the sectional analysis, gas exporters would be "treated just like consumers of natural gas, that is, no regulation after the gas leaves the domestic pipeline system." Therefore, commingled gas to be exported would be treated in the same manner as domestic gas while it is in the domestic pipeline.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 13: What state agency actions (which are not already preempted by Federal law) would proposed Natural Gas Act section 3(d) authorize the President to preempt? Please give specific examples.

Answer: Upon finding that an exportation or importation is in the national interest, proposed section 3(d) of the Natural Gas Act would give the President the authority (1) to waive any law relating to the exportation or importation, or (2) to specify that a law relating to the exportation or importation shall be considered satisfied, even though a Federal or State agency with jurisdiction has not taken final action.

This authority for the President could function as a substitute for the way that Federal law is supreme under the present statutory scheme. Currently, when the Department of Energy authorizes an import and the Commission has approved the site of importation, section 3 of the Natural Gas Act preempts any State action that would be inconsistent with DOE's import authorization or conditions thereon, or the Commission's siting approval. Similarly, if S. 570's modifications to section 3 are enacted, thereby removing importation and exportation from Federal regulation, the President would be able to act to preempt State actions that would be inconsistent with a determination by the President that the national interest requires that a particular importation take place in a certain way, including importation at a particular site. Again, much would depend on how narrowly or broadly this provision would be construed.

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 14: Would proposed Natural Gas Act section 3(d) authorize the President to overturn any Federal or State law relating to the exportation or importation of natural gas, or deem as being satisfied any federal or state law, if it is found that "the exportation or imporation of natural gas is in the national interest"?

Answer: Yes. Proposed section 3(d) of the Natural Gas Act would apply to "any law relating to the importation or exportation of natural gas."

QUESTIONS FOR THE RECORD FROM SENATOR DOMENICI

Question 15: In proposed Natural Gas Act section 3(d) what does the phrase "relating to" refer to? How expansively should it be read? For example, would it apply to environmental laws?

Answer: The courts have determined, because of the involvement of foreign commerce, that current section 3 of the Natural Gas Act is "plenary and elastic" and broader than section 7 of that Act. The clear purpose of S. 570's proposed Federal deregulation of importation and exportation is to remove unnecessary restrictions, not to allow greater opportunity for State regulation of imports and exports. Thus, it would appear that proposed section 3(d) would permit the President to preempt any State action that would impede an importation or exportation that is in the national interest. The President's authority would apparently apply to environmental laws so that he could waive compliance with those laws if necessary. Once again, given the importance of how the phrase "relating to" is to be interpreted, the statute and legislative history should address this question with as much specificity as possible.

QUESTION FOR THE RECORD FROM SENATOR DOMENICI

Question No. 16: On February 28, 1991, FERC issued an order remanding a comprehensive pipeline settlement filed by CNG Transmission Corporation covering some 20 docketed cases in Docket No. RP88-211-000, *et al*. The case involved a fundamental, long-term restructuring of rates and services by the pipeline company and various customers and other parties. FERC remanded the settlement back to an Administrative Law Judge (ALJ) after the ALJ had certified the settlement to the Commission as "uncontested." None of the 27 parties to the proceeding, including state public utility commissioners and consumer counsels, requested FERC to return the settlement back to an ALJ for more delay in a trial environment.

Provide an explanation of the policy reasons why FERC sent this uncontested settlement agreement back to hearing before an ALJ.

Answer: The Commission's February 28, 1991 order approved part of CNG's settlement with respect to rates and refunds for a past period. It only remanded to the ALJ one aspect of the settlement, which concerned the rate design to be applied in the future. Under the Commission's current rate design policy, the Commission evaluates the rate design to determine whether the rates are consistent with the Commission's economic efficiency and other policy objectives, even if the settlement is unopposed. In this instance, the parties failed to cite to sufficient record information to permit the Commission to evaluate the rate design, so the Commission directed a narrow remand to develop the record necessary to evaluate the rate design. In addition, the Commission found it necessary to defer action on other aspects of the service restructuring settlement since CNG had only entered into new agreements for restructured services with some, but not all its customers. This matter is now pending rehearing before the Commission.

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SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
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April 4, 1991

Senator J. Bennett Johnston
Chairman, Committee on Energy and
Natural Resources
364 Dirksen Senate Office Building
Washington, D.C. 20510-6150

Dear Senator Johnston:

Thank you for allowing me to testify at the March 7, 1991 hearing on Title X of the National Energy Security Act of 1991 (S.341) before the Committee on Energy and Natural Resources. Attached are answers to the follow-up questions of your March 11, 1991 letter.

Again, I enjoyed appearing before your Committee and hope that my testimony will be of value to the Committee during its deliberations. Please do not hesitate to contact me or Sonat's Washington office if you have additional questions.

Yours very truly,

Ronald L. Kuehn, Jr.
Chairman, President and
Chief Executive Officer

cc: Mr. Donald Santa

April 4, 1991

ANSWERS OF RONALD L. KUEHN, JR.
TO POST-HEARING QUESTIONS
BEFORE THE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
MARCH 7, 1991

I. Post-hearing Questions of Senator J. Bennett Johnston

Questions

In your testimony, you express considerable skepticism over the value for the interstate natural gas pipeline industry of the optional procedures for pipeline construction contained in S.341 (SECS. 10001 and 10002).

1. Could these options be modified to address your concerns? Please suggest how this might be done. Please include suggested substitute language if to do so would be helpful.

2. Assuming that your concerns could be addressed, are there any circumstances where the availability of these optional procedures would be beneficial to an interstate pipeline?

Answers

The optional procedures of S.341 include construction under section 311 of the Natural Gas Policy Act (NGPA) and an "optional certificate" procedure which would result in a certificate being issued under section 7 of the Natural Gas Act (NGA) after completion of construction. These options are in addition to the traditional section 7 certificate procedure which requires that the Federal Energy Regulatory Commission (Commission) find the proposed facilities to be in the public convenience and necessity.

As a general matter, I fear that the options would create bad policy and, therefore, must be modified. I am concerned that elimination of the Commission's responsibility to ensure that facilities are "in the public convenience and necessity" (by defining satisfaction of that condition to be anything a pipeline does at its own risk (optional procedure) or by allowing construction of large interstate non-jurisdictional facilities (section 311), will result in additional costs with unknown rate consequences. After all, the gas transmission business is a capital intensive one -- excess capacity means either high unit costs or financially weak companies. For example, incremental analysis may produce a perfectly viable case for a new pipeline to serve large industrial customers presently served by a local distribution company (LDC) via an existing pipeline. An alternative means of serving these customers would create excess capacity and a lower load factor operation on the LDC and the existing pipeline. Since the LDC and pipeline would still serve the existing residential and commercial (R&C) requirements after the new pipeline takes away the industrial customers, R&C rates would go up. The industrial customers may have lower costs, but at the expense of homeowners. This is the type of public interest injury that section 7 was designed to avoid.

The modifications to section 311 proposed by S.341 can be modified to avoid this problem and I suggest the appropriate modification below. The optional certificate procedures cannot be satisfactorily modified and therefore, I would recommend that it should be dropped.

Finally, I, for one, do not think that the traditional certification process necessarily prevents pipelines from pursuing new markets. In fact, the industry has put a lot of new pipe in the ground since its peak delivery of 22 trillion cubic feet in 1972. I believe that the goal of this legislation should be to streamline the approval process, not to sow the seeds of another round of "transition" and its associated costs. The following are some more specific comments on the optional procedures.

Sec. 10001 Optional Certificate Procedure

The optional certificate procedure proposed in S.341 allows a pipeline to build transportation facilities without a certificate. Upon commencement of transportation services through the facilities built under this option, a certificate of public convenience and necessity under section 7 of the NGA shall be issued to the natural gas company. The natural gas company is required to accept the certificate, which may contain conditions the FERC finds are required by the public convenience and necessity. The rates are further subject to section 5 review, and the cost of the facilities can not be rolled in for 10 years. Federal eminent domain is not available under this procedure.

Some of the problems a pipeline would have with this are obvious:

1. The pipeline would be forced to accept unknown conditions.

2. The rate is market based (value of service) originally but can be subsequently lowered based on just and reasonable (cost based) standards.

Other reasons are less obvious:

1. The rate is required to be incremental based on the new facility. New services on existing pipelines, however, will use both old facilities and the new facilities. The new customer will, therefore, be charged two rates and the legislation does nothing to modify FERC treatment of rates for that portion of the new service which is performed through old facilities. For existing pipelines, therefore, the total transaction will never be market driven or market priced.

2. Incremental rate making (charging separate rates for service through old and new facilities) virtually always produces higher rates than rolled in rate making (charging one rate for service through both old and new facilities).

Any time different classes of competitors are created, unintended dislocations can occur. Totally new pipelines may have competitive advantages over old pipelines under this legislation. This would create unequal classes of competitors.

In my written testimony I state that this optional certificate proposal will not offer a meaningful solution to the regulatory delay problem which this legislation is intended to solve. The reason, as described above, is that this does not create a market based alternative. The only thing it creates is delayed regulation and, therefore, regulatory second guessing. I do not believe that it will be at all useful, at least to existing pipelines. The only solution to this regulatory risk is to make the options truly deregulated and, because of the need to use the whole pipeline, the only way to do this is to completely deregulate pipelines; that is, repeal the Natural Gas Act in its entirety.

As suggested, my comments do not apply as forcefully to an incremental pipeline (built solely to connect a new supply to a market). An incremental pipeline would be fully subject to the risks of retroactive regulatory review (second guessing) and, therefore, this proposal may not even be attractive for that construction. If such optional certificate construction procedures are attractive, however, new pipelines will be favored over existing pipelines and the use of these new pipelines may cause significant damage to existing pipelines and their customers. Most new pipe is put in the ground to attach new supplies to existing pipelines in order to serve existing markets or to improve load factor on existing facilities by attaching new markets to existing pipelines. If new pipelines preempt this function, existing pipelines and their residential customers would face higher costs and shortages.

Finally, I am very concerned that the mere existence of this option would have a negative effect on the Commission's timeliness in processing traditional certificates. In my written testimony I noted that in the past the Commission has forced construction under alternate procedures by either refusing to process traditional section 7 applications or by inordinate delay in doing so. These proposals could result in a "Mexican Standoff" with pipelines refusing to use the options and FERC delaying or denying traditional section 7(c) certificates to encourage use of the options. This obviously would produce the exact opposite result from that intended by the bill. As further evidence, the Commission has had an optional expedited mechanism in place since the issuance of Order 500 in 1985, and has not established reasonable or reliable procedures for pipelines to utilize.

Sec. 10002 Amendments to Section 311 of the NGPA

The amendments to section 311 of the NGPA would specifically allow construction of any size and type pipeline under section 311 and to authorize any interstate pipeline to transport "on behalf of" any person (emphasis added to denote proposed change from existing laws). In addition, the bill provides that section 311 transportation shall not be unjust, unreasonable, unduly discriminatory or preferential (within the meaning of the NGA).

Sonat does not view section 311 authorization as an attractive alternative for most major construction even with the changes of S.341. It does not provide federal eminent domain and carries significant rate uncertainties, namely that its rate treatment in a future rate case is an unknown. Sonat believes, however, that the changes of S.341 may prove helpful in some instances and, therefore, supports these changes with one major exception.

The modification allowing transportation "on behalf of any person" is an invitation to bypass LDCs and existing pipelines for important industrial loads. Sonat believes that this could prove very harmful to residential and commercial customers in the form of higher rates which could lead to further load loss. Rather than create a divisive issue, and serious potential harm, Sonat suggests the use of the American Gas Association position which would require traditional section 7 procedures to be used for situations where the construction would create a bypass of existing pipelines or LDC's.

II. Post-hearing questions of Senator J. Bennett Johnston to Panel II of the hearing on Title X of S.341 March 7, 1991

Question

1. To the extent necessary, please supplement your testimony with a more detailed analysis of Title II of S.570, the National Energy Strategy Act. Please address both the policy implications of Title II and questions raised by the individual provisions of Title II.

Answer

As I noted in both my written and oral testimony, I have serious concerns that certain aspects of the National Energy Strategy (NES) Act could have very significant negative impacts on the natural gas transmission industry. I am concerned primarily with the same thing I mentioned with regard to S.341, unequal classes of competitors. The NES causes me even more concern than S.341 because it purports to completely deregulate one class of competitors.

This legislation restructures the gas transmission industry by allowing new interstate pipelines to be constructed without federal regulation. This represents a major change from the federal oversight of the last 50 years, the period in which the vast majority of pipelines were built. The legislation does not remove the regulation of existing facilities. As a result, it creates a situation where regulated entities would be competing with non-regulated entities. The ability of the regulated entities to respond to competition from unregulated competitors is restricted by existing regulations and regulatory pricing. I am very concerned that this bill may have totally unintended results not unlike the 1954 Phillips decision which regulated the price of gas at the wellhead, allowed other fuels to remain unregulated, and led to the serious shortages of the 1970s.

The pipeline industry is a mature industry and new pipe is usually put in the ground for two purposes:

1. to allow the existing markets of a pipeline access to sufficient new gas supplies by replacing depleted sources;

2. to improve utilization of existing pipelines in order to lower unit costs.

New unregulated pipelines can be created to match the best new supplies with the best new and old markets at the expense of existing pipelines and their existing customers. The best markets are not residential which are low load factor and require extensive storage facilities to serve. Existing pipelines will, therefore, continue to serve residential requirements. What can happen, however, is "cherry picking". These new, non-jurisdictional pipelines could attach important new gas fields and link them with important industrial markets. The result could be increased costs and curtailments of high-priority residential requirements on old pipelines while lower priority industrial loads are fully served by these new pipelines. This would not be in the public interest.

Generally, the free market is the best allocator of resources. However, the interstate natural gas pipeline industry is not a free market. The NES purports to establish "free market" pipelines to compete with regulated pipelines and the result is not market based allocation of resources; the result is unfair competition.

For the above reasons, I believe that the deregulation provisions of the NES are not in the best interest of the public. Rather than run the risks associated with creating unequal classes of competitors, which would threaten the important public interests associated with protecting the residential and commercial consumers, I would suggest a more conservative approach. The Bingaman Amendments address the real problem with the current system, that is, delay.

I support S.341 Section 10006 setting rehearing and court review limits. I believe that the Bingaman Amendment requiring the Commission to issue a certificate after 60 days and addressing the problem of protests that are inconsequential or contrary to a demonstration of "conclusive evidence of need" are the answers to the excessive certificate review time. I believe that S.341 section 10003 and the Bingaman Amendments adequately address the delays in the environmental review process. These provisions would effectively eliminate all of the disadvantages of using section 7 for pipeline construction while retaining all of the significant public policy advantages (and safeguards). Therefore, I think that the optional procedures are unnecessary and should not be enacted for the reasons expressed in my written testimony.

As you will recall, I urged in both my written and oral testimony that the legislation enacted not produce further major restructuring at a significant cost to an industry still attempting to recover from the recent restructuring which cost in excess of $9 billion. I continue to be concerned about the legislation going beyond what is required to cure the problems with the current system and in the process creating new problems.

Question

2. In particular, please address Section 201 of S.570, the so-called mandatory interconnect provisions.

   a. What are the policy issues raised in connection with this section?

b. Does the section achieve its stated purpose of authorizing the FERC to order upstream interconnection but not downstream interconnection, i.e., bypass?

c. What are the technical questions raised by the manner in which Section 201 is drafted? How would you resolve these questions? Please provide suggested substitute language if to do so would be helpful.

Answer

I read the provisions of the NES as not mandating direct connection in the market area, but nevertheless, I think that any mandatory interconnection provision is bad policy and should be removed. There are two reasons that I believe this section should not be enacted. First, the thrust of the NES is towards less, not more regulation, towards use of market, not regulatory signals. This provision goes in the opposite direction creating more regulation and overriding market based actions.

Second, it is an unnecessary regulatory intrusion. I have seen no evidence of pipelines refusing to attach new gas supplies. To the contrary, virtually every time our pipelines engage producers in discussions involving attachment of new supplies, there are other pipelines competing with us to attach the same supplies. Producers are obtaining discounted transportation rates in many cases in consideration for attaching new supplies to a pipeline. Even if refusal to connect were occurring, the existing anti-trust laws and anti-discrimination provisions of the Natural Gas Act (as well as the Outer Continental Shelves Act) should offer producers adequate protection.

Finally, I am totally opposed to mandatory connections at the market end of pipelines and I do not see how Congress can create different policies at each end of the pipe. I do not see any "technical" issues with the drafting of section 201, just important policy issues which lead me to oppose section 201.

III. Post-hearing Questions of Senator Domenici

Question

1. Do you support the Commission's open access transportation program?

Answer

Sonat supports open access transportation. Southern Natural Gas Company has operated as an open-access pipeline since accepting its Commission certificate. Southern has settled its take-or-pay expense rate issues and is moving forward in the new world of open access transportation. Southern has, however, had a gas inventory charge languishing before the Commission for two years.

If your question encompasses the issue of whether pipelines were dealt with fairly in the structure and implementation of open access transportation, the answer is emphatically no! The Commission restructured Southern's contracts at one end of the system and did nothing at the other. Commission regulations allowed pipeline customers to reduce takes of gas which they were contractually obligated to take, without granting pipelines the commensurate right to reduce takes from producers. However, that fairness issue is behind Southern now. This issue relates to the pending legislation only to the extent that pipelines have enjoyed enough restructuring to last a lifetime and need some certainty to complete the "open access" restructuring, not more restructuring.

Question

2. If sections 204 and 205 of S.570 were adopted, what impact would that have on the Commission's open access transportation program?

Answer

As I stated earlier, I believe that sections 204 and 205 run a great risk of creating two unequal classes of competitors for certain business. While I focused on residential customers as the primary injured party from this (because they have less flexibility than any other class of customer), existing open access customers (at least to the extent they cannot take advantage of the non-jurisdictional option) would also be injured. If a pipeline cannot attach new gas sources in the face of non-jurisdictional competition, existing transporters may not be able to buy gas on the system and will either do without or pay more transportation charges to get gas to the transporting pipeline. Likewise, if the pipeline's throughput is reduced due to non-jurisdictional competitors, unit costs would increase for all users, industrial transporters as well as residential customers. So, there is clearly a potential for a negative impact on existing open access systems.

With regard to the new pipelines constructed under sections 204 or 205, there is no reason to believe that such pipelines would be open access systems. Although open access may be imposed as a condition subsequent to construction of a pipeline under section 204, open access is not certain. In any event, there is nothing in existing law to provide for open access in a pipeline constructed under proposed section 205. There would be no such open access requirement for a section 205 pipeline unless Congress passes something essentially mandating common carriage, which seems to contradict the concept of a "non-jurisdictional" option.

Question

3. Would you prefer the NGPA Section 311 amendments in S.341 or those in S.570?

Answer

I do not support either in their present form. Section 311 of the NGPA of 1978 was intended to allow an interstate natural gas pipeline to transport on behalf of an LDC or intrastate pipeline. The purpose was to facilitate the movement of natural gas to the interstate system, and by and between the interstate and intrastate systems. Both S.341 and S.570 would allow transportation on behalf of any person which will encourage bypass, load loss and resulting injury to existing customers. The provisions of S.570 in addition require 30 day notice to state commissions in cases of bypass. Sonat believes the 30 day notice requirement is a step in the right direction but not nearly far enough. An amendment which would require a section 7 certificate in instances of bypass is crucial to avoiding serious potential problems.

Question

4. What changes would you recommend to be made to sections 203, 204 and 205 of S.570?

Answer

I would recommend eliminating sections 204 and 205 of S.570. I also believe section 203 must be amended to avoid the contentious bypass issue and the serious potential harm which could arise from encouraging bypass. As stated, I would suggest making the provisions of section 203 inapplicable to bypass situations.

Department of Energy
Washington, DC 20585
April 17, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 7, 1991, Stephen A. Wakefield, General Counsel, testified before your committee on Title X of S. 341.

Following the hearing, you submitted written questions on behalf of Senators Bingaman, Wirth, Wallop and Domenici to supplement the record. Enclosed are the answers. The remaining answer to question 8 (Wirth) is still in the clearing process and will be forwarded to you as expeditiously as possible.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Renee Wilhite, on (202) 586-4277.

Sincerely,

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

Department of Energy
Washington, DC 20585

April 26, 1991

APR 2 [illegible]

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 7, 1991, Stephen A. Wakefield, General Counsel, testified before your committee on Title X of S. 341.

At the time of my last letter to you dated April 17, 1991, we explained that the remaining question for the record was not available and that it would be forwarded to you. Enclosed is the answer to that question.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Renee Wilhite, on (202) 586-4277.

Sincerely,

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosure

QUESTIONS FROM SENATOR BINGAMAN

Question 1:	Please provide greater details on how the proposed Natural Gas and Electric Administration within the Department of Energy would be organized and how it would function. In particular, how would the NGEA differ from the Federal Energy Regulatory Commission in the performance of the functions now performed by the Commission?
Answer:	Under this proposal, FERC, similar to the existing Energy Information Administration, would become an administration within DOE. This new administration would be headed by an Administrator, who would report to the Secretary and participate in key policy decisions made through DOE's existing policy-making framework. However, responsibility for that policy would reside in the Secretary.

The proposal for natural gas regulatory and structural reform contained in the NES is intended to promote competition and streamline and improve the overall efficiency of the construction and rate authorization process. The proposal to change FERC's status from an independent regulatory commission, located within the Department of Energy, to an Administration, still situated within the Department of Energy, is complementary to the overall strategy for natural gas reform. The principal advantages of the proposed structure are as follows:

a. Establishment of a Coordinated Energy Policy

Policy should be developed and implemented within the context of considerations of the full range of governmental interest in all relevant areas. In the case of FERC, it is clear that the existing bifurcated structure for dealing with natural gas problems does not lend itself to the fulfillment of sound energy policy.

The lack of effective coordination over the development of all aspects of natural gas policy implementation prevents the execution of a coherent energy strategy by DOE. While certain portions of natural gas and electricity policy result from decisions at DOE and elsewhere in the Executive Branch, these policies are implemented in individual proceedings at the FERC which cannot be discussed with officials from the Executive Branch.

b. Policy Implementation

Under the current FERC structure policy must be implemented through individual proceedings or settlements. However, under the concept of "separation of functions" as practiced by FERC, the ability of the policymakers to communicate their objectives in the implementation of that policy with that portion of the FERC staff responsible for the proceedings is extremely limited. This may result in positions being taken by FERC staff which are totally inconsistent with the views of the Commission; proceedings adjudicated on faulty premises; and decisions which do not reflect the policy directives desired by those responsible for policy formulation.

c. Streamlined Decisionmaking

Since FERC is a multiheaded agency, its procedures are unwieldy and time-consuming. Decisions cannot be made after due consideration by a single responsible executive. Instead, they require concurrence by a majority of the Commissioners. Since the Government in the Sunshine Act requires that all meetings of more than two Commissioners be subject to notice and open to the public, timely action and a free and full exchange of views is inhibited. The necessity to obtain the votes of three Commissioners prior to the issuance of any order frequently results in delays and the necessity to achieve compromises which may do nothing to protect consumers or the public interest. These problems are compounded when the Commission (as is often the case) has fewer than five Commissioners. Under our proposal, one administrator would be responsible for reviewing the decisions made by the ALJs and issuing final orders.

In conclusion, just as the structure of the FERC reflects the old attitude toward natural gas regulation that engendered the existing regulatory scheme, the proposed legislation reflects a new posture toward natural gas and electricity regulation. The entire reform proposal, both substantive and procedural, would promote an efficient regulatory scheme that would allow the energy industry to respond promptly to market conditions and demands. In addition, the Administration's FERC reorganization proposal would provide for a unitary regulatory structure that would be responsive to any future changes in the Nation's energy policy.

QUESTIONS FROM SENATOR BINGAMAN

Question 2: Would Administrative Law Judges still be required to adjudicate individual rate and certificate cases? Would the integrity of the adjudicative process still be protected by ex parte rules and would such rules apply to the Administrator in his consideration of contested cases?

Answer: Individual proceedings requiring impartial adjudicative hearings would be conducted by administrative law judges ("ALJ") within DOE, and their decisions would be subject to review by the Administrator, as the delegate of the Secretary. The Administrator would be responsible for the prompt processing of all applications filed with the agency, including the assignment of matters to ALJs for hearings. The Administrator would also be responsible for ensuring that the staff of the Administration is seeking to implement properly policy directives of the Secretary. The provisions of the Administrative Procedure Act (hereinafter "APA"), including those limiting ex parte contacts by a decisionmaking official, would apply to adjudications conducted by the Department to the same extent that those provisions applied to the exercise of those functions by the FERC. In fact, the extent to which the provisions of the APA apply to these functions are, and would continue to be, determined by the provisions of the substantive Acts under which the functions are authorized. See Department of Energy Organization Act § 641 (hereinafter "DOE Act").

QUESTIONS FROM SENATOR BINGAMAN

Question 3: Would the Administrative Procedure Act continue to apply to the NGEA in its performance of the functions previously within the jurisdiction of the FERC? Would the NGEA be required to initiate notice and comment rulemakings before promulgating generic rules governing the natural gas and electric industries and would such rulemakings be subject to judicial review?

Answer: As described above, the extent to which the APA applies to functions originally transferred to FERC by the DOE Act, and the proposed amendments thereto, is determined by the provisions of the substantive Acts under which the transferred functions are authorized; therefore, the APA will apply to those functions as performed by the NGEA to the same extent that they applied to the FERC. However, as amended, Section 501(a) of the DOE Act specifically would impose a further requirement that the provisions of the Administrative Procedure Act ("APA") found in subchapter II of chapter 5 of title 5, United States Code, including those requiring notice and comment, apply to the issuance of all rules by the Department, including those which previously would have been under the authority of the FERC. Section 501 of the DOE Act imposes additional procedural requirements upon rules and regulations proposed by the Department pursuant to any authority transferred to the Secretary. In addition, the DOE Act provides that judicial review of any agency action, taken under any law for which responsibility for administration has been transferred to the Secretary (in this case the Natural Gas Act, the Federal Power Act, etc.) shall be governed by the provisions of the law authorizing the action. Thus, judicial review of NGEA actions taken under those laws will be identical to that which currently applies to FERC actions under those same laws. DOE Act § 502(a).

Question 4: What types of actions by the NGEA would require Secretarial approval? Will this result in added layers of review for matters on which the FERC currently may take final action?

Answer: Because the proposed restructuring would vest authority in the Secretary, and the Secretary would delegate that authority to the Administrator of the NGEA, the Secretary would have the authority to review any decision made by Administrator. The increase in decisional efficiency provided by the single Administrator, combined with likelihood that the Secretary will exercise his right to substantive review only in exceptional cases, will result in an overall decrease in regulatory delay.

QUESTIONS FROM SENATOR WIRTH

Question 1: The N.E.S. legislation would deregulate imports and exports of natural gas. Does this mean that the Administration believes the United States has no complaint with current exports of natural gas into the U.S., and does not need regulatory leverage to change the conditions surrounding those exports?

Answer: The Administration believes the current level of natural gas imports is entirely consistent with the goal of providing American consumers adequate energy supplies at reasonable prices. As a general rule, we believe that free trade in energy supplies serves American consumers better than the imposition of regulatory reviews of energy trade. We recognize, however, that there may be instances in which it may be appropriate for the President to prohibit or condition the import or export of natural gas. Accordingly, our proposed section 3(c) of the NGA would provide for such an authority. Our legislation also does not diminish FERC's existing ability to inquire into these issues as they bear on the pricing of natural gas and related services offered to U.S. customers, nor does it affect FERC's jurisdiction over facilities transporting imported natural gas within the U.S.

QUESTIONS SUBMITTED BY SENATOR TIMOTHY E. WIRTH

Question 2A: What is the current level of proved natural gas reserves in the North Slope area of Alaska?

Answer: The Energy Information Administration lists approximately 9 trillion cubic feet of natural gas as proved reserves for the State of Alaska. A large majority of these reserves are located on the North Slope.

There are, however, an additional 24.6 trillion cubic feet of gas that are physically producible on the North Slope. Improved economic conditions in the future, and the subsequent means to deliver this gas to a market, could move these resources into the proved reserves category.

Question 2B: What percentage of total natural gas reserves in the United States, as shown in the NES, are located on the North Slope of Alaska?

Answer: The NES lists current U.S. proved reserves as 168 trillion cubic feet of natural gas. Presently, less than 5 percent of these proved reserves are located on the North Slope. There are, however, an additional 24.6 trillion cubic feet of gas that are physically producible on the North Slope. Improved economic conditions in the future, and the subsequent means to deliver this gas to a market, could move these resources into the proved reserves category.

QUESTION FROM SENATOR WIRTH

Question 2c: Has the Administration approved an application for the export of large volumes of natural gas from the North Slope of Alaska?

Answer: Yes. On November 16, 1989, the Department of Energy issued Opinion and Order No. 350, which granted Yukon Pacific Corporation an authorization to export 16.5 trillion cubic feet (Tcf) of liquefied natural gas (LNG) to the Pacific Rim countries of Japan, South Korea, and Taiwan over a twenty-five year period.

Question 2d: Given that the Department has approved the export of these reserves, is it fair to count them in the total available for U.S. use?

Answer: Yes. The export authorization approved by the Department does not in any way commit any reserves of gas to the export. Those reserves belong to the North Slope producers and will have to be purchased from a producer by any party desiring to sell them. Departmental approval of the export proposal does not ensure that this project will become operational; the marketplace will make that determination; thus, the effect of this export authorization on North Slope reserves is unknown at this time.

QUESTION FROM SENATOR WIRTH

Question 2e: Isn't there an alternative pipeline proposal for bringing North Slope gas to U.S. markets?

Answer: Yes. There is a proposal to bring North Slope gas to the lower 48 states via the Alaska Natural Gas Transportation System (ANGTS). However, the decision to build ANGTS will be determined by the marketplace and the willingness of the owners of the North Slope reserves to sell their gas to the ANGTS sponsors.

Question 3: Is the current level of proven North Slope gas reserves sufficient to economically justify both the export project as approved by DOE in Opinion Nos. 350 and 350-A and the Alaska Natural Gas Transportation System ("ANGTS") as approved by Congress?

Answer: The Department of Energy and Congress never committed the North Slope reserves to the Yukon Pacific export proposal nor the ANGTS, respectively. The marketplace will determine whether any or both of these projects are economically justifiable.

QUESTION FROM SENATOR WIRTH

Question 4: If the ANGTS is completed in accordance with the 1977 Presidential and Congressional decisions approving the project, how much Alaskan gas could be delivered to United States consumers and over what period of time?

Answer: ANGTS sponsors have stated that the project could supply 2.3 Bcf per day of natural gas over a twenty-five year period.

Question 4: What is the oil equivalent of the North Slope gas that could be delivered daily through the ANGTS?

Answer: Up to 600,000 barrels per day.

QUESTIONS FROM SENATOR WIRTH

Question 5. Please explain how DOE's authorization of exports of North Slope gas in Opinion Nos. 350 and 350-A can be reconciled with the following:

(a) the congressional declaration in the Alaska Natural Gas Transportation Act ("ANGTA"), 15 U.S.C. 719, that the construction of "a viable natural gas transportation system for delivery of Alaska natural gas to United States markets is in the national interest";

Answer: Opinion Nos. 350 and 350-A explicitly considered the relationship between the authorization of exports of North Slope natural gas and ANGTA and determined that such an authorization was consistent with ANGTA. ANGTA is a procedural statute enacted to establish a process for selecting a transportation system to bring natural gas from the North Slope of Alaska to the lower-48 states and to facilitate its construction and operation. Nothing in Opinion Nos. 350 and 350-A affects the special statutory and regulatory treatment for ANGTS that remains ready to be used whenever its sponsors decide to resume its construction.

QUESTIONS FROM SENATOR WIRTH

Question 5(b):	the President's 1977 Decision and Report to Congress on the Alaska Natural Gas Transportation System, which was subsequently ratified by Congress;
Answer:	There is no provision in the Decision and Report to Congress on the Alaska Natural Gas Transportation System that prohibits the export of North Slope natural gas. The Decision did, however, provide for special regulatory treatment of ANGTS. Opinion Nos. 350 and 350-A are quite clear in their assertion that this treatment is not affected by the export authorization.

QUESTIONS FROM SENATOR WIRTH

Question 5(c): the commitments which the United States have made to Canada, including those contained in the 1977 "Agreement Between the United States of America and Canada on Principles Applicable to a Northern Natural Gas Pipeline," relating to completion of the ANGTS; and

Answer: Opinion Nos. 350 and 350-A carefully considered the effects of an export authorization on the agreements between the U.S. and Canada concerning ANGTS. These opinions found that the U.S. Government has complied fully with its commitment to ANGTS by removing all regulatory impediments to the completion and operation of ANGTS by private parties and has assured Canada that it will not erect new regulatory barriers to the completion of ANGTS by private parties. Opinion Nos. 350 and 350-A contain nothing that affects these commitments by the U.S. Government.

QUESTIONS FROM SENATOR WIRTH

Question 5(d): the prior findings by Congressional committees that Section 12 of ANGTA would permit exports of North Slope gas "only under an exchange arrangement whereby U.S. consumers would not be faced with increases in energy prices nor a reduction in the total quantity or quality of energy." (See, e.g., Joint Report of the Senate Committees on Commerce and Interior and Insular Affairs Together With Minority and Additional Views on S-3521 to Expedite a Decision on the Delivery of Alaska Natural Gas To United States Markets and For Other Purposes, S. Rep. No. 1020, 94th Cong., 2nd sess. 22023 (1976).

Answer: There is nothing in the statutory language of section 12 of ANGTA that limits exports of North Slope natural gas to exchange arrangements. Section 12 only requires a finding by the President that "exports will not diminish the total quantity or quality nor increase the total price of energy available to the United States." President Reagan issued such a finding on January 12, 1988. In addition, Opinion Nos. 350 and 350-A examined independently the effects of exports of North Slope natural gas on American consumers and found that exports would not reduce the energy supplies available to consumers nor raise the price of these supplies.

QUESTIONS FROM SENATOR WIRTH

Question 6: The ANGTS was approved after several years of trial-type hearings before the Federal Power Commission, predecessor to the Federal Energy Regulatory Commission. Is it true that DOE authorized the export proposal without any trial-type hearing whatsoever?

Answer: Unlike FERC, DOE does not routinely utilize trial-type hearings to consider requests for import and export authorizations. DOE did comply with all applicable statutory, regulatory, and procedural requirements in the proceeding that resulted in Opinion Nos. 350 and 350-A. This proceeding took over two years and provided an opportunity for comments, reply comments, oral presentations (including a public conference held in Anchorage), and rehearing of issues.

QUESTIONS FROM SENATOR WIRTH

Question 7: In 1981, DOE's former General Counsel, R. Tenny Johnson, testified before the Senate Energy Committee that "there would have to be a legislative act to permit the exportation of natural gas from Alaska." See, The President's Recommendation.-Hearing Before the Senate Committee on Energy and Natural Resources, 97th Cong., 1st Sess. 143 (1981). Similarly, I understand that former Secretary of Interior William Clark sent a letter to the Chairman of Yukon Pacific Corporation on March 20, 1984, stating that "there is an existing legislative Commitment to ANGTS for delivering North Slope gas reserves to the domestic market," and that "legislation may be necessary to authorize another transportation project." Does the DOE still maintain this view? If so, how can Opinion Nos. 350 and 350-A be reconciled with that view? If DOE has reversed the position taken by its former General Counsel and the former Secretary of Interior, please explain the basis for the reversal.

Answer: DOE has never taken a formal position that ANGTA prohibits the export of North Slope natural gas. Statements by various officials prior to the issuance of Opinion Nos. 350 and 350-A were made in response to hypothetical questions and without the benefit of thorough research on the issue. Opinion Nos. 350 and 350-A carefully researched this issue and found that ANGTA did not bar export. Rather, section 12 of ANGTA sets forth the procedural requirements that must be met in order to export North Slope natural gas.

QUESTION FROM TIMOTHY E. WIRTH

Question 8: Have any DOE officials attempted to persuade foreign companies or foreign countries to purchase North Slope gas or to otherwise support Yukon Pacific's proposed export project? If so, please provide a list of all meetings or discussions which involved these efforts, as well as the names and positions of all parties who participated.

Answer: U.S. policy on Alaska North Slope gas is to remove any regulatory barriers that would prevent this gas coming to market on a commercial basis. The objective is that all market options should be open to achieve and maintain a competitive and efficient market that allows natural gas to develop to is its full potential.

Under the 1983 Joint Policy Statement signed by President Reagan and Prime Minister Nakasone, it was agreed that both countries would encourage their private sector to look into joint development of Alaska natural gas as one means of furthering the close economic and energy security relationship between our countries. Since then in the energy bilateral meetings with Japan and Korea that are usually held twice year, we have encouraged countries in the Far East to consider Alaska gas as a secure and diverse source to supply their growing needs. We have emphasized that this should be done only on a commercial basis and between private companies. We have not supported any specific company or project that would export gas to the Far East.

QUESTIONS SUBMITTED BY SENATOR TIMOTHY E. WIRTH

Question 9A: Does the Department of Energy support section 9701 of S.341, which would restrict the export of oil produced from ANWR?

Answer: The NES Act contains no prohibition on the export of ANWR crude oil. This is due to the uncertainties associated with the timing and size of a potential discovery, the projected declines in current North Slope production, and the market situation at some future point in time. The Department will continue to monitor and analyze the North Slope oil supply situation and make appropriate recommendations as additional information becomes available.

Existing statutory restrictions on the export of oil transported through the Trans Alaska Pipeline System (TAPS) are contained in section 7(d) of the Export Administration Act of 1979 (currently kept in force by the President under the International Emergency Economic Power Act). These restrictions would apply to ANWR oil transported through TAPS, just as they now apply to Alaskan North Slope production. Consequently, no further legislation seems needed on this subject.

In addition, the Department notes that section 9701, as currently drafted, may raise concerns regarding the U.S.-Canada Free Trade Agreement and contains certain technical problems.

QUESTIONS SUBMITTED BY SENATOR TIMOTHY E. WIRTH

Question 9B: Does the Department of Energy support or oppose the existing restriction of export of oil transported through the Trans Alaska Pipeline (TAPS)?

Answer: The Department does not oppose the retention of the existing statutory restrictions on the export of oil transported by TAPS. The Department does believe that there are valid economic reasons to allow the export of North Slope crude oil in order to encourage domestic production, but it is not presently seeking to alter these restrictions.

QUESTIONS FROM SENATOR WIRTH

Question 10: FERC currently has statutory responsibility to act on a petition for a rehearing within 30 days. However, it has routinely delayed resolution of these issues by simply committing before the 30 day limit to a re-hearing which can be anytime in the future. Do you support reasonable limits for final disposal of petitions for rehearing?

Answer: In S. 341, section 3006 would amend both the Natural Gas Act (NGA) and the Natural Gas Policy Act of 1978 (NGPA) by providing that, after a 60 day period from the date of the filing of an application for rehearing of a Federal Energy Regulatory Commission (FERC) order, if FERC has not taken final action, the rehearing request shall be deemed denied. FERC may extend the rehearing period for an additional 60 days only for "extraordinary cause." This section is intended to prevent FERC from avoiding final action on rehearing by issuing a tolling order, which in many cases delays final resolution by months and even years. We support it.

Question 11A: Please provide analysis of what fuels have replaced the 3 TCF of gas representing the decline in annual gas use in this country over the past 20 years. In what economic sectors, and in what geographic regions of the country, has this decline in gas use occurred?

Answer: Natural gas consumption in the United States has declined by more than 3 trillion cubic feet since the peak in 1972. (Figure 1). Much of the decline occurred in the industrial and electric utility sectors, sectors which are very price-sensitive. Smaller declines occurred in lease and plant fuel, residential, and pipeline fuel use. Commercial consumption increased slightly. (Table 1).

From the 1972 peak usage, consumption by electric utilities declined by 1.2 trillion cubic feet. About 75 percent of this decline is seen in two regions: the West South Central where consumption declined by 27 percent or 543 billion cubic feet and the West North Central where consumption declined by over 90 percent or 376 billion cubic feet. Use of natural gas in this sector increased over this period in some regions. In the Middle Atlantic region, natural gas consumption increased by 136 billion cubic feet, more than doubling the usage from 1972.

Consumption of natural gas in the industrial sector was 1.4 trillion cubic feet lower in 1989 than 1972. Industrial use of natural gas has shown substantial swings over the period. One of the lowest levels occurred around 1982-1983, a period when the price of natural gas increased by 33 percent over 1981 prices. Consumption in this sector has been increasing over the past three years as the price of gas has been competitive with the alternative fuels.

During this same time period, total energy consumption in the United States increased almost 10 quadrillion Btu. (Table 2). Coal and nuclear electricity showed the biggest gains. Each had 6 percent more of the Nation's total energy consumption in 1989 than they did in 1972. Natural gas declined from 32 percent of total consumption to 24 percent. In the industrial sector, all fuels showed decreases except electricity. Coal and natural gas each lost 3 percent while petroleum gained 1 percent and electricity increased by 5 percent of total industrial consumption. In the electric utility sector, coal showed a large increase, going from 52 percent to 78 percent of total consumption by electric utilities. Natural gas use dropped from 27 percent to 14 percent.

Figure 1.

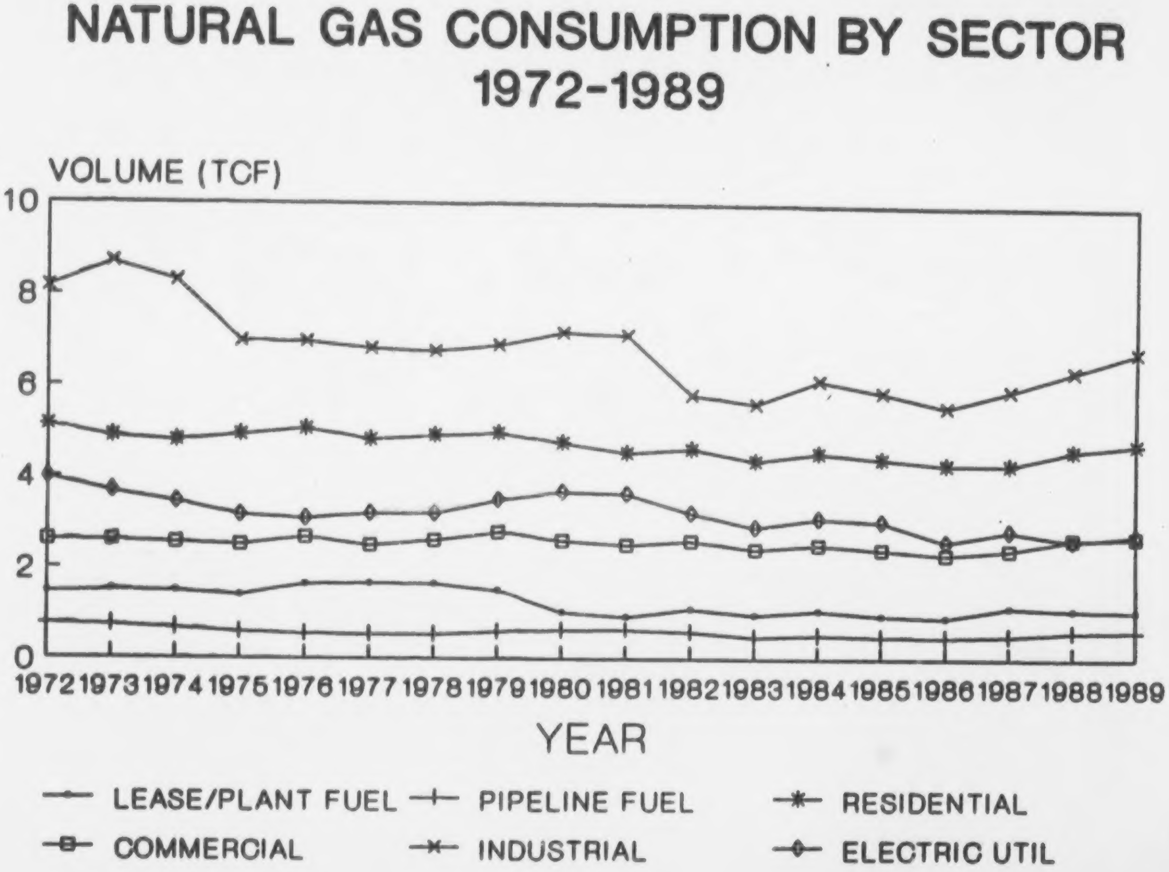
NATURAL GAS CONSUMPTION BY SECTOR
1972-1989
VOLUME (TCF)
10
8
6
4
2
0
1972
1973
1974
1975
1976
1977
1978
1979
1980
1981
1982
1983
1984
1985
1986
1987
1988
1989
YEAR
LEASE/PLANT FUEL
PIPELINE FUEL
RESIDENTIAL
COMMERCIAL
INDUSTRIAL
ELECTRIC UTIL

Table 1: Natural Gas Consumption by Sector and Census Division (Bcf)

RESIDENTIAL	1972	1989	CHANGE
NEW ENGLAND	138	180	42
MIDDLE ATLANTIC	819	831	12
EAST NORTH CENTRAL	1,595	1,500	-95
WEST NORTH CENTRAL	548	465	-83
SOUTH ATLANTIC	364	375	11
EAST SOUTH CENTRAL	232	188	-44
WEST SOUTH CENTRAL	449	402	-47
MOUNTAIN	273	246	-27
PACIFIC CONTIGUOUS	699	575	-124
PACIFIC NONCONTIGUOUS	8	14	6
TOTAL	5,126	4,777	-349

COMMERCIAL	1972	1989	CHANGE
NEW ENGLAND	62	100	38
MIDDLE ATLANTIC	333	446	113
EAST NORTH CENTRAL	722	678	-44
WEST NORTH CENTRAL	367	310	-57
SOUTH ATLANTIC	215	252	37
EAST SOUTH CENTRAL	151	128	-23
WEST SOUTH CENTRAL	284	277	-7
MOUNTAIN	190	187	-3
PACIFIC CONTIGUOUS	269	318	49
PACIFIC NONCONTIGUOUS	16	24	8
TOTAL	2,608	2,719	111

INDUSTRIAL	1972	1989	CHANGE
NEW ENGLAND	50	65	15
MIDDLE ATLANTIC	551	424	-127
EAST NORTH CENTRAL	1,529	1,097	-432
WEST NORTH CENTRAL	552	374	-178
SOUTH ATLANTIC	625	574	-51
EAST SOUTH CENTRAL	524	420	-104
WEST SOUTH CENTRAL	3,126	2,995	-131
MOUNTAIN	412	182	-230
PACIFIC CONTIGUOUS	787	625	-162
PACIFIC NONCONTIGUOUS	12	59	47
TOTAL	8,169	6,816	-1,353

Table 1: Natural Gas Consumption by Sector and Census Division (Bcf)

ELECTRIC UTILITIES	1972	1989	CHANGE
NEW ENGLAND	9	54	45
MIDDLE ATLANTIC	105	241	136
EAST NORTH CENTRAL	194	33	-161
WEST NORTH CENTRAL	405	29	-376
SOUTH ATLANTIC	265	223	-42
EAST SOUTH CENTRAL	130	47	-83
WEST SOUTH CENTRAL	2,001	1,458	-543
MOUNTAIN	250	111	-139
PACIFIC CONTIGUOUS	606	539	-67
PACIFIC NONCONTIGUOUS	13	33	20
TOTAL	3,977	2,768	-1,209

	1972	1989	CHANGE
LEASE/PLANT FUEL	1,456	1,070	-386
PIPELINE FUEL	766	630	-136
U.S. TOTAL	22,101	18,780	-3,321

Source: Natural Gas Annual

Table 2:

Total Consumption (Quadrillion Btu)

	1972	%	1989	%	Diff.
Coal	12.08	17	18.92	23	6.84
Natural Gas	22.70	32	19.50	24	-3.20
Petroleum	32.95	46	34.02	42	1.07
Hydro Electric	2.94	4	2.85	4	-.09
Nuclear Electric	.58	1	5.69	7	5.11
Other	.01	0	.25	0	.24
Total	71.26	100	81.23	100	9.97

Industrial Consumption (Quadrillion Btu)

	1972	%	1989	%	Diff.
Coal	3.97	16	2.89	13	-.08
Natural Gas	9.88	40	8.26	37	-1.62
Petroleum	8.53	35	8.19	36	-.34
Electric	2.22	9	3.15	14	.93
Total	24.61	100	22.49		-1.12

Electric Utility Consumption Quadrillion Btu)

	1972	%	1989	%	Diff.
Coal	7.81	52	15.95	78	8.14
Natural Gas	4.08	27	2.85	14	-1.23
Petroleum	3.10	21	1.68	8	-1.42
Total	14.99		20.48		5.49

Source: AER 1989

QUESTION FROM SENATOR WIRTH

Question 11B. Please provide us with your analysis of the causes of this use decline.

Answer: The primary reasons for the reduction in natural gas consumption were: (1) the regulation-induced shortages of natural gas that occurred in the mid-1970s and undermined consumer confidence in the supply base; (2) subsequent legislation prohibiting the use of natural gas in new electric generating facilities (The Powerplant and Industrial Fuel Use Act); (3) the sharp increase in natural gas prices in the late 1970s and early 1980s precipitated by the Natural Gas Policy Act of 1978; (4) conservation; and (5) continuing regulatory constraints on the ability of the natural gas industry to be an effective competitor in the energy marketplace (including difficulty in constructing new natural gas facilities in a timely, efficient way). The attribution of precise quantities of the total reduction in gas use to each causal factor is not possible at this time.

QUESTION FROM SENATOR WIRTH

Question 11c: Please provide us with whatever analysis you have done on what barriers have contributed to this decline, in rough order of their contribution.

Answer: Many factors have impacted the use of natural gas in the United States. The natural gas industry has been a heavily regulated industry from the wellhead to the burnertip. Price controls in the 1970's resulted in a declining portion of natural gas being committed to the interstate market during the early part of that period, while the intrastate portion of the market had abundant supplies. Many initiatives have been undertaken to remove or mitigate barriers and market imperfections. These included the Wellhead Decontrol Act of 1989, removal of restrictions on the use of natural gas imposed by the Fuel Use Act, repeal of the incremental pricing provision of the Natural Gas Policy Act, and market restructuring resulting from FERC orders, including Order 436/500. Since 1985, the transmission of market signals from the producer to the consumer has improved substantially. Natural gas consumption over this period has increased.

The National Energy Strategy has identified the following as barriers remaining to a more efficient natural gas market:

- Regulatory uncertainty and delay in building new pipeline capacity because of outmoded economic regulation and cumbersome environmental review proceedings.

- Continued regulation of natural gas transactions, including arrangements between consenting buyers and sellers, that is not required to protect against the abuse of market power.

- Pricing schemes that discourage natural gas pipelines and consumers from using existing capacity most efficiently.

- Failure to ensure access to pipeline services on a nondiscriminatory basis for third-party shippers (shippers other than the pipeline and its affiliates).

- Unnecessary regulation of natural gas imports and exports.

- Restrictions on exploration for and development of natural gas in certain areas of the Outer Continental Shelf.

QUESTION FROM SENATOR WIRTH

Question 12: Why is natural gas now priced at half the already low cost of oil on an energy-equivalent basis?

Answer: Natural gas historically has not sold at prices even approximately equal to the Btu-equivalence price of crude oil (see Table below.)

The disparity in gas-to-oil prices may be attributed to a number of factors, including regulation, transportation differentials, gas-on-gas competition, and the existence of significant markets, especially transportation, where natural gas is not an effective competitor with oil.

The transportation differentials reflect the higher costs to move natural gas compared to petroleum liquids over equivalent distances.

The relative abundance of natural gas at present results in a buyers' market in which sellers compete vigorously with one another to sell more gas.

Relative Price of Natural Gas and Crude Oil Prices, 1970-1990 (Nominal Dollars)

	Oil[1] (\$/bbl)	Gas[2] (\$/mcf)	Gas-to-Oil Ratio
1970	\$3.18	\$0.17	30.1%
1971	\$3.39	\$0.18	29.9%
1972	\$3.39	\$0.19	31.6%
1973	\$3.89	\$0.22	31.8%
1974	\$6.87	\$0.30	24.6%
1975	\$7.67	\$0.44	32.3%
1976	\$8.19	\$0.58	39.9%
1977	\$8.63	\$0.79	51.5%
1978	\$9.56	\$0.91	53.6%
1979	\$13.01	\$1.18	51.1%
1980	\$22.65	\$1.59	39.5%
1981	\$33.71	\$1.98	33.1%
1982	\$30.43	\$2.46	45.5%
1983	\$28.00	\$2.59	52.1%
1984	\$27.59	\$2.66	54.3%
1985	\$25.74	\$2.51	54.9%
1986	\$14.13	\$1.94	77.3%
1987	\$16.83	\$1.67	55.9%
1988	\$13.97	\$1.69	68.1%
1989	\$17.12[p]	\$1.71[p]	56.2%
1990	\$21.06[e]	\$1.77[p]	47.3%

[e]: Estimated.
[p]: Preliminary.

Sources: Prices of crude oil and natural gas, 1970-1989: *EIA Annual Energy Review 1989;* 1990 based on preliminary values used for the *Annual Energy Outlook 1991;* relative price ratio is derived.

Notes: bbl means barrel, and mcf means thousand cubic feet.

[1]: 1970-1989 from Crude Oil Domestic First Purchase Price, excluding Alaska North Slope, Table 65, page 145.

[2]: 1970-1989 from Natural Gas Wellhead and Import Prices, Table 77, page 173.

QUESTIONS FROM SENATOR WALLOP

Question 1: As proposed in the National Energy Strategy the deregulation of existing interstate pipelines is to be contingent on two preconditions: first, that a pipeline provides comparable service to third-party shippers, and second that a pipeline does not have market power in either the producing field or in the selling market.

However, it appears that the section 205 non-jurisdictional option could be used to remove an existing pipeline from federal regulation through "acquisition" even if the preconditions are not met (new NGA section 7(k)(1). Is that a drafting error?

Answer: Section 205 does allow the acquisition and operation of a pipeline without a certificate if the conditions specified in that section are met. However, such an authority could not, in and of itself, remove an existing pipeline from FERC's regulatory jurisdiction under the Natural Gas Act. Because the existing pipeline would continue to have in force a certificate of public convenience and necessity under section 7(c), the seller of such a pipeline would be required to seek permission and approval from FERC for abandonment of its obligations under that certificate pursuant to section 7(b) before it could cease the certificated operations. In order to allow abandonment of a certificate, the FERC must conduct hearings and find "that the present or future public convenience and necessity permit such abandonment." In such a hearing, the FERC would address concerns raised by shippers and customers regarding the service to be offered by the deregulated pipeline, including issues related to comparability of service and market power.

QUESTIONS FROM SENATOR WALLOP

Question 2: What are S. 570's preconditions for non-regulation of new pipelines?

Answer: Section 204 of S. 570 establishes optional certificate procedures under which facilities may be constructed by an applicant which has received a certificate from the FERC under the provisions of a new section 7(i) of the NGA. Section 205 of S. 570 provides for a new section 7(k) of the Natural Gas Act under which a person may elect to build new pipeline facilities without a FERC certificate of public convenience and necessity. A person electing to build facilities under these provisions are barred from participating in any proceeding which is considering an application for a certificate for construction or extension of facilities which would compete with the facilities built under these provisions. The costs of facilities, whether constructed under the optional certificate procedures or the nonjurisdictional option, could not be included at any later date in a rate filing under section 4 of the Natural Gas Act for these or other facilities. Thus, the pipeline bears the full risk associated with these facilities. Rates or charges for service through the facilities would be based upon negotiations with shippers or customers and not subject to FERC jurisdiction.

Under the new certificate provisions of S. 570, the FERC would not be required to make a specific finding that a new pipeline to be certificated under new section 7(i) or authorized under new section 7(k) would offer comparable third party transportation and participate in competitive markets before those pipelines could be constructed. The Administration believes that such a finding is unnecessary with respect to new pipelines because new pipelines do not possess market power prior to construction. The removal of barriers to entry due to the new certificate provisions will result in a market in which any number of companies can compete to build a new pipeline. Thus, an informal, competitive bidding process will take place as pipelines attempt to sign up customers prior to construction in order to ensure the economic viability of the project. This bargaining process would be sufficiently competitive to justify exempting new pipelines from regulation.

However, after a pipeline is constructed, if a person seeks service from a pipeline operated under a section 7(i) certificate or section 7(k), but cannot get service or agree upon the rate offered, that person would be permitted to petition the Commission for a rate which is not unduly discriminatory. This would not be a cost-based, just and reasonable standard, but rather a requirement for the pipeline to provide a similar rate for a similar service offered, if capacity is available. In our view, this safety net provides an adequate protection to the pipeline's customers, fully analogous, and perhaps superior in its impact to protections offered under the FERC's existing open access policy.

QUESTIONS FROM SENATOR WALLOP

Question 3: For both new pipelines that are exempted from regulation and existing pipelines which are deregulated, what protections and remedies against discrimination and unfair practices would producers have under S. 570?

Answer: As discussed in Question #2, both producers and consumers are "protected" against discrimination by the existence of competition by many parties to build new capacity. Producers and consumers only need governmental protection when competitive market forces will not be sufficient to prevent monopoly abuse. To provide further protection from a lack of competition, Section 201 of the NES Act would expand section 7(a) such that when adequate capacity exists, FERC would have the right to direct a pipeline to interconnect physically with other facilities, at the applicant's expense, in order to receive natural gas from the other facilities for transportation in the pipeline. This will assure that producers will be able to deliver their gas into a pipeline and be able to compete for sales on that system. However, consistent with the existing provisions of section 7(a) regarding deliveries out of a pipeline to a local distribution company, pipelines could not be compelled to expand their facilities or establish physical interconnection if that would impair the pipeline's ability to render adequate service to its customers.

In addition, S. 570 provides certain "safety net" procedures to a person who alleges undue discrimination and seeks access to available capacity on the pipeline. These safety net provisions, discussed extensively in question # 2, provide customers, including producers, the necessary protection.

QUESTIONS FROM SENATOR DOMENICI

Question 1: Does the Department support the Commission's open access transportation program?

Answer: The Department believes that, in the context of the existing regulatory structure, FERC's open access policy has provided a vital stimulus to competition in natural gas markets. However, it has been almost six years since Order No. 436 was issued. True nondiscriminatory access, including the nondiscriminatory provision of comparable transportation and other services to third party shippers, has not yet been achieved.

QUESTIONS FROM SENATOR DOMENICI

Question 2: If sections 204 and 205 of S. 570 were adopted how would that affect the Commission's open access transportation program?

Answer: FERC's open-access transportation program would not be affected with respect to existing or future pipelines certificated under traditional section 7(c) procedures. Because shippers are protected by competition by many potential builders of pipeline capacity, it is not necessary to rigidly dictate terms and conditions of service for those parties who contract with the builder of new capacity. Since a certificate issued to a pipeline pursuant to section 204 is contingent solely upon compliance with criteria set forth in the legislation, FERC may not, and in fact, does not need to, require a pipeline to be open-access by utilizing its current practice of incorporating such a requirement into the pipeline's certificate in order to protect shippers from monopoly abuse. Similarly, pipelines authorized under section 205 are not required to obtain a certificate as long as they comply with the conditions specified in the legislation.

For shippers who may want to contract witht he pipeline after it is built, the legislation specifies that a pipeline operating under either of these provisions would be subject to the requirements of the new section 7(j). Section 7(j) provides that if a potential shipper is unable to reach agreement with such a pipeline for access on a not unduly discriminatory basis, it may petition the FERC for an order directing the requested transportation to commence within 60 days unless FERC finds adequate capacity is unavailable. FERC would have the authority to issue a rulemaking to implement the criteria for evaluating when a denial of service is "unduly discriminatory."

QUESTIONS FROM SENATOR DOMENICI

Question 3: The National Energy Strategy report indicates that comparable third party transportation and competitive markets are necessary prerequisites to the deregulation of pipelines.

a. Does S. 570 require those two prerequisites to be met before an existing pipeline is deregulated?

Answer: Yes. The only "deregulation" of existing pipelines specifically provided for in S. 570 is the new Natural Gas Act section 4(g), added by section 205, which would authorize the FERC to issue an order finding that rates charged by a natural gas company in a given market are not within the Commission's jurisdiction if, after a hearing, the Commission finds that the market in issue is competitive and that the natural gas company involved offers service to that market on a basis that is not unduly discriminatory. Such a finding of competitiveness ensures that the two criteria in the NES report--comparability of service and competitive markets--are met.

b. Would they be required if a new pipeline is to be not regulated?

Answer: Under the new certificate provisions of S. 570, the FERC would not be required to make a specific finding that a new pipeline to be certificated under new section 7(i) or authorized under new section 7(k) would offer comparable third party transportation and participate in competitive markets before those pipelines could be constructed. The Administration believes that such a finding is unnecessary with respect to new pipelines because new pipelines do not possess market power prior to construction. The removal of barriers to entry due to the new certificate provisions will result in a market in which any number of companies can compete to build a new pipeline. Thus, an informal, competitive bidding process will take place as pipelines attempt to sign up customers prior to construction in order to ensure the economic viability of the project. This bargaining process would be sufficiently competitive to justify exempting new pipelines from regulation.

After a pipeline is constructed, if a person seeks service from a pipeline operated under a section 7(i) certificate or section 7(k), but cannot get service or agree upon the rate offered, that person would be permitted to petition the Commission for a rate which is not unduly discriminatory. This would not be a cost-based, just and reasonable standard, but rather a requirement for the pipeline to provide a similar rate for a similar service offered, if capacity is available. In our view, this safety net provides an adequate protection to the pipeline's customers, fully analogous, and perhaps superior in its impact to protections offered under the FERC's existing open access policy.

c. Proposed Natural Gas Act section 7(k)(1) appears to allow the deregulation of an existing pipeline through acquisition but does not appear to require the two NES prerequisites. Is that a drafting error?

Answer: Section 205 does allow the acquisition and operation of a pipeline without a certificate if the conditions specified in that section are met. However, such an authority could not, in and of itself, remove an existing pipeline from FERC's regulatory jurisdiction under the Natural Gas Act. Because the existing pipeline would continue to have in force a certificate of public convenience and necessity under section 7(c), the seller of such a pipeline would be required to seek permission and approval from FERC for abandonment of its obligations under that certificate pursuant to section 7(b), before it could cease the certificated operations. As stated above, in order to allow abandonment of a certificate under section 7(b), the FERC must conduct hearings, and find "that the present or future public convenience and necessity permit such abandonment." In such a hearing, the FERC would address concerns raised by shippers and customers regarding the service to be offered by the deregulated pipeline, including issues related to comparability of service and market power.

d. If a pipeline were exempted from regulation, how could the Commission or the Department ensure the NES preconditions of comparable third party transportation and competitive markets would continue to exist following deregulation?

Answer: We believe it unlikely that a market found to be competitive could become uncompetitive. Antitrust authorities are available to prevent acquisitions which have such an effect. As for market growth, the certificate reform provisions in S. 570 would allow potential new pipeline construction to serve as a restraint upon the abuse of market power.

e. What would prevent a deregulated pipeline from discriminating against, or even excluding entirely, an independent producer, and what remedy would that producer have?

Answer: As described above, if competition is present, it will ensure that producers have a variety of options to move natural gas to market. Where competition is not present, if person seeks service from a pipeline operated under a section 7(i) certificate or section 7(k), but cannot get service or agree upon the rate offered, the person would be permitted to petition the Commission for services and rates that are not unduly discriminatory. Also, section 201 of S. 570 would add a new NGA section 7(a)(2) that would give FERC the authority to direct an interstate pipeline, including those authorized by new NGA section 7(k), to establish physical connection with the facilities of a petitioning person for delivery of gas to the pipeline.

QUESTION FROM SENATOR DOMENICI

Question 4a: Is there a factual basis to find that the existing market for gas at the border crossings with Canada and at the tailgates of LNG gasification plants are competitive?

Answer: Yes. The substantial number of freely negotiated sales of Canadian gas to U.S. buyers evidences the competitiveness of these markets. During 1990, 98 firms imported approximately 1.5 Tcf of natural gas into the United States. All major Canadian import points were utilized by numerous Canadian gas suppliers. Moreover, all operating LNG facilities served markets that had access to other gas supply sources.

Question 4b: In view of the commanding role played by TransCanada Pipelines Ltd. and its marketing affiliate, how could such a finding be made?

Answer: TransCanada Pipeline Ltd. is an open-access transporter. During 1990, TransCanada transported natural gas for over 50 Canadian gas importers. In addition, a large percentage of Canadian gas imports serving the West Coast and Midwest do not need to use TransCanada's facilities; gas transported to these markets use other Canadian transporters; i.e., Westcoast Transmission Company Ltd., Foothills Pipe Lines Company Ltd.

QUESTIONS FROM SENATOR DOMENICI

Question 5: Assume that a U.S. pipeline transporting Canadian gas to a U.S. market is providing open access transportation. Also assume that competing U.S. pipelines to the same market are not offering open access transportation.

a. If the pipeline which is offering open access transportation applies for decontrol pursuant to proposed section 4(g) of the Natural Gas Act, would the fact that the competing pipelines serving the same area market are not offering open access transportation be a factor in determining whether the pipeline should be exempted from regulation? Would that factor alone be sufficient to deny the 4(g) deregulation application?

Answer: Proposed section 4(g) requires that the Commission make a finding that the market served by the pipeline which is to be deregulated is competitive and that the pipelines services are offered to that market on a not unduly discriminatory basis. Whether or not any competing pipelines serving that market are open access pipelines would certainly be a factor to be considered in the Commission's finding. In making its finding, the Commission must take all factors affecting the level of competition in the market into account; the absence of alternative open access pipelines would be one factor in the Commission's decision. Its significance would depend upon other conditions present in the market.

b. Who would have the burden of proof in a sec. 4(g) proceeding?

Answer: In a proceeding under proposed section 4(g), the burden of proof would be upon the petitioning natural gas company.

c. Would a state commission be preempted from reviewing the purchases made by a local distribution company from a pipeline deregulated pursuant to section 4(g)?

Answer: No, not by the terms of the legislation.

QUESTIONS FROM SENATOR DOMENICI

Question 6: Section 212 of S. 570 would appear to define "importation" to include all "actions involved in bringing natural gas into the United States." Would this include sales and transportation downstream from the border?

Answer: The term "Importation" is intended to cover those activities that are currently regulated by the Secretary of Energy under the DOE Act. FERC currently regulates sales and transportation downstream from the border under the NGA sections 4, 5 and 7 authority transferred to it by the DOE Act and various delegation orders issued by the Secretary of Energy. Accordingly, the definition of "importation" would not affect FERC's authority to continue to regulate these activities which are not currently the responsibility of the Secretary.

Question 7: Suppose that gas sold at the border in a first sale is resold by a marketer. Would that resale also be exempted from Natural Gas Act jurisdiction under the proposed Natural Gas Act section 3(a)?

Answer: Proposed section 3(a) of the Natural Gas Act only deals with first sales. Proposed section 3(a) would not cover any resale transaction.

QUESTIONS FROM SENATOR DOMENICI

Question 8: Under proposed Natural Gas Act section 3(b), would FERC retain the jurisdiction to "level the playing field" regarding differences in rate design between U.S. and Canadian gas?

Answer: Under section 213 of S. 570, the proposed section 3(b) of the Natural Gas Act would require FERC to treat imported and domestic natural gas the same. Equal treatment does not preclude FERC from determining and requiring the pass through of costs by domestic pipelines on the same basis for imported and domestic natural gas.

Question 9: Could proposed Natural Gas Act section 3(c) or 3(d) be used to overturn or preempt the U.S.-Canada Free Trade Agreement?

Answer: Neither proposed section 3(c) nor 3(d) of the Natural Gas Act is intended to provide a basis to overturn or preempt the U.S.-Canada Free Trade Agreement.

Question 10: Could proposed Natural Gas Act section 3(d) be used to overturn FERC Opinion No. 256?

Answer: Proposed section 3(d) of the Natural Gas Act is not intended to provide a basis to overturn FERC Opinion No. 256.

QUESTIONS FROM SENATOR DOMENICI

Question 11: Regarding domestic first sale under the NGPA, FERC has interpreted the guaranteed passthrough provision as entitling the purchaser the opportunity to try to recover costs in commodity rates and not necessarily the guarantee of "as billed" treatment. Could proposed section 3(b) be used to give imported gas regulatory advantage over domestic gas?

Answer: Proposed section 3(b) of the Natural Gas Act could not be used to give imported gas a regulatory advantage over domestic gas. In fact, it mandates the principle that imported and domestic gas are to be treated in exactly the same manner.

Question 12: To the extent that gas to be exported is commingled with gas consumed in the United States prior to export, would proposed section 3(b) prohibit FERC from imposing conditions on the commingled stream even if the same conditions apply to the domestically consumed gas?

Answer: Proposed section 3(b) of the Natural Gas Act would only prohibit FERC from imposing conditions on the export of natural gas. To the extent FERC currently regulates under its NGA sections 4, 5 and 7 authority those aspects of a commingled stream of gas to be consumed domestically and to be exported, proposed section 3(b) would not prevent it from continuing to regulate the commingled stream in the same manner.

QUESTIONS FROM SENATOR DOMENICI

Question 13: What state agency actions which are not already preempted by Federal law would proposed Natural Gas Act section 3(d) authorize the President to preempt? Please give specific examples?

Answer: Section 3 of the Natural Gas Act currently preempts all State actions that are inconsistent with an import or export authorization. Specific examples would depend upon the terms of the authorization. Proposed section 3(d) would provide for the continuance of federal preemption with respect to deregulated imports and exports.

Question 14: Would proposed Natural Gas Act section 3(d) authorize the President to overturn any federal or state law relating to the exportation or importation of natural gas, or deem as being satisfied any federal or state law, if it is found that "the exportation or importation of natural gas is in the national interest"?

Answer: Proposed section 3(d) of the Natural Gas Act would apply to any law relating to the exportation or importation of natural gas.

QUESTIONS FROM SENATOR DOMENICI

Question 15: In proposed Natural Gas Act section 3(d) what does the phrase "relating to" refer to? How expansively should it be read? For example, would it apply to environmental laws?

Answer: The phrase "relating to" in proposed section 3(d) of the Natural Gas Act is intended to be read broadly enough to deal with all situations that might deter an import or export project that the President determines to be in the national interest. For example, the President could use this authority to establish a timetable for compliance with NEPA.

ADDITIONAL QUESTION OF SENATOR DOMENICI

Question: On February 28, 1991, FERC issued an order remanding a comprehensive pipeline settlement filed by CNG Transmission Corporation covering some 20 docketed cases in Docket No. RP88-211, *et al*. The case involved a fundamental, long-term restructuring of rates and services by the pipeline company and various customers and other parties. FERC remanded the settlement back to an Administrative Law Judge (ALJ) after the ALJ had certified the settlement as "uncontested." None of the 27 parties to the proceeding, including state public utility commissioners and consumer councils, requested FERC to return the settlement back to an ALJ for more delay in a trial environment.

Is this another instance where FERC effects barriers to natural gas markets because of "Continued regulation of natural gas transactions, including arrangements between consenting buyers and sellers, that is not required to protect against abuse of market power"?

Answer: The National Energy Strategy advocates eliminating regulation of transactions between consenting buyers and sellers of natural gas if the transaction involves a pipeline which has been constructed under new procedures or has obtained abandonment authorization that has been shown to lack market power. If this legislation were enacted, DOE believes that significant barriers to efficient pipeline utilization would be removed.

To the extent that rate regulation is required under existing law, we generally support the Commission's May 30, 1989, policy statement on the design of pipeline transportation rates ("Policy Statement"), which we believe will strengthen competition in natural gas transportation and sales markets. "Interstate Natural Gas Pipeline Rate Design," 54 Fed. Reg. 24,382 (June 7, 1989), 47 F.E.R.C. ¶ 61,295, order on reh'g, 48 F.E.R.C. ¶ 61,122. In fact, we believe that the Commission, if anything, should require stricter compliance with the Policy Statement. In the order in the CNG Transmission Corporation case, the Commission indicates, that, although the settlement before the Commission was uncontested, the parties had failed to "provide a basis for concluding that CNG's seasonally differentiated rates are appropriate for CNG's system, or that any other aspect of its rate design is consistent with the Commission's rate design objectives." CNG Transmission Corporation, Docket Nos. RP88-211-000, et al., mimeo at 8. The Commission stated that a remand to an ALJ for the "expeditious supplementation of the record" was necessary before the Commission could render an opinion that the settlement was consistent with the Commission's Policy Statement. Id. The Department can not render an opinion as to whether, in this case, supplementation of the record was necessary;

however, as stated above, the Department supports the Commission's attempts to require that those pipelines subject to rate regulation comply with the Policy Statement. It must be noted that, under the NES proposals, it would be possible for CNG Transmission Corporation to seek abandonment of the relevant facilities or services or to prove that it lacks market power and that it provides its services on a not unduly discriminatory basis. If the Commission agreed with the applicant, further regulation of its rates would be unnecessary. In such a case, the Department believes that regulation of the pipeline's rates would be unnecessary and that a major regulatory barrier to efficient pipeline transportation would be removed.

Appendix II—Additional Material Submitted for the Record

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April 12, 1991

VIA HAND DELIVERY

Donald F. Santa, Jr., Counsel
United States Senate Committee
on Energy and Natural Resources
364 Dirksen SOB
Washington, D.C. 20510

Re: **Senator Wirth's "Gas Policy Reform Act," S.662, and "National Energy Efficiency and Development Act," S.741 and S.742; and the Administration's "National Energy Strategy Act," S.570.**

Dear Mr. Santa:

On March 19, 1991, the American Public Gas Association (APGA) submitted a prepared statement for the Committee's hearing record regarding Title X of S.341 (the "National Energy Security Act of 1991"), certain amendments proposed by Senator Bingaman thereto, and the Administration's proposal to abolish the Federal Energy Regulatory Commission (FERC). In that statement, the APGA reserved the right to make further comment as the need arose. This supplemental statement provides the APGA's views on the regulatory issues and "accelerated pipeline construction" provisions of S.662, S.741 and S.742 (hereinafter collectively referred to as S.662) and the natural gas title of S.570.

I.

S.662, the "Gas Policy Reform Act"

APGA shares the concerns regarding S.662 expressed by Mr. Ronald J. Binz, on behalf of the National Association of State Utility Consumer Advocates (NASUCA), in his testimony before the Committee. It is not clear to APGA that the provisions of this bill will meet its stated goal, to "increase the use of

natural gas in the United States," but may in fact decrease the use of natural gas because it will lead to increased rates for small customers, arbitrary abandonment of service, and the shifting of the risk to natural gas customers of cost responsibility for uneconomic pipeline facilities.

Mr. Wirth was quoted in the "Gas Daily" on March 15, 1991, and in "The Energy Report" on March 18, 1991, as saying that past attempts to reform gas regulation have been stymied by "controversy between segments of the gas industry, each looking after its own interests." S.662 certainly would resolve a number of controversies, but all in favor of the pipelines! Controversies concerning pipeline monopoly service should be left to resolution before the appropriate regulatory body, FERC, where all segments of the natural gas industry and consuming public can make their interests known.

Mr. Wirth was also quoted in those same articles as having said that "[t]he complicated adversarial regulatory system we have built up for regulating gas over the years has, in effect, kept gas from the people who need it." In truth, though, this regulatory the system has required pipelines to provide and maintain service to numerous small customers in many circumstances where the pipelines were otherwise unwilling to initiate or continue such service.

Provisions of S.662 would unfairly shift costs and risks to customers through changes in rate design and would mandate the automatic "as-billed" flowthrough of producer demand charges to customers. Monopoly pipeline companies would be permitted to extract higher rates of return from firm services, and would be able to arbitrarily abandon sales service. Moreover, rather than increasing competition by encouraging new investors to construct pipelines, S.662 provides unfair advantages for existing pipeline companies. Thus, pipeline companies will be protected from both competition from new entrants and the risk of their investments.

The captive natural gas customer, unlike the long distance telephone customer, does not have the physical capability to chose among a plethora of long distance interstate pipelines. Even if the construction of new pipelines is encouraged by this proposed legislation, these pipelines would be located in the production area and would not extend to the city gates of the great majority of natural gas distribution systems. Small distributor-customers have one, and only one, source of pipeline capacity to obtain their required gas supplies -- the pipeline that was required by the FERC (and before it, by the FPC) to serve their respective communities with firm sales service. Small customers do not have bargaining power, or storage facilities, or true market access. The pipelines which serve small distributor-customers are still monopolies, and these customers must be protected from the abuse inherent in monopoly service. Just as many small towns either no longer have airline service or now pay exorbitant fares for such service, and just as many small communities are losing their bankrupt banks, S.662 would lead to both increased rates and the loss of natural gas service to many small communities.

II.

S.570, the "National Energy Strategy Act" (NES)

This bill goes far beyond either S.341, S.662, or H.R.779 (Representative Sharp's "Natural Gas Enhancement Act of 1991"), towards deregulation of the natural gas industry. While it attacks one derivative facet of Natural Gas Act (NGA) Section 7 proceedings, i.e., the opportunity for competitors to participate in such proceedings, it ignores the fundamental purpose of such NGA proceedings, i.e., the opportunity for natural gas distributor-customers and consumers to be heard in an objective forum regarding proposed pipeline construction and rates since they will be the ones to receive (or be denied) service from and to pay the costs of the facilities to be constructed. The NGA was enacted to protect the public interest and to ensure that natural gas facilities, for which the public would have to pay, would be necessary to serve the public and would be "used and useful." In this crucial aspect, the industry has not significantly changed since the NGA was enacted because most pipelines still have monopoly power over most customers. Customers still need the protections offered by the NGA, but S.570, unfortunately, would effectively eliminate those protections.

Contrary to the contentions of the Administration, service and construction under Section 311 of the Natural Gas Policy Act (NGPA) is hardly "adrift" in uncertainties. As noted in APGA's initial comments, the breadth of the "on behalf of" standard has been thoroughly litigated at FERC and in the courts, where all factions of the industry had full and fair hearings. To change this standard now would introduce uncertainty, and lead to further litigation. As for allowing major construction under section 311, APGA also stated its opposition in its initial comments. APGA agrees with the comments of the Natural Gas Supply Association (NGSA) that such a broadening of construction authority under Section 311 is not necessary (since the NGA Section 7 regulated option already exists and assuming there will be a deregulated option of some kind included in any natural gas legislation enacted by this Congress) and inappropriate (because the pipeline will get the benefit of regulation, i.e., shared risk of costs, while not having to submit to regulatory approval through proof that construction is necessary and in the public interest).

APGA strongly opposes those portions of S.570 which would provide for optional certificate procedures and nonjurisdictional certificate procedures. The optional certificate procedures proposed in S.570 do not include the protections and procedural safeguards afforded by those proposed in S.341. Again, nonjurisdictional pipelines are out of the question given the current status of the industry. Small distributors and consumers must be protected from the monopoly power of the pipeline that is physically connected to their town. Deregulation may encourage construction of pipelines in the production area, but more pipelines will not be built to small towns where the market is less lucrative. Section 7(a) of the NGA was written because pipelines have historically been unwilling to even provide sales service to small towns, let alone competitive transportation service.

APGA could support the provisions in S.570 regarding mandatory interconnection if they were properly conditioned. It should be clarified that the notice and hearing procedures of existing Section 7(a) would apply to mandatory interconnection actions. The petitioner for mandatory interconnection should be required to bear all associated costs related to the relevant interconnection. And, if Section 7(a) is to be amended, it should be broadened to include transportation service as well as sales service. Any new version of Section 7(a) must require that mandatory interconnections meet the existing statutory standards of not creating any undue burden or an impairment of existing services.

Finally, APGA reemphasizes that it is strongly opposed to the abolishment of FERC, as fully stated in its initial comments.

APGA thanks the Committee for this opportunity to present its views. APGA reserves the right to comment further as the need arises. If there are any questions, please do not hesitate to call me.

Sincerely,

Robert S. Cave

Robert S. Cave
Executive Director

cc: All Members of the Committee on Energy and Natural Resources, U.S. Senate
Stanley W. Balis, Esquire

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March 19, 1991

Donald F. Santa, Jr.
Counsel
United States Senate
Committee on Energy
and Natural Resources
364 Dirksen Building
Washington, D.C. 20510

RE: S.341

Dear Mr. Santa,

As per our telephone conversation of last Friday, please find enclosed the comments of the American Public Gas Association (APGA) regarding:

1. S.341;
2. Amendment 19 (Senator Bingaman's Amendments to S.341); and
3. the provision of the Administration's NES calling for the abolishment of the FERC.

I am providing four printed copies and a copy on a "floppy" disk. It is my understanding that these comments will be included in the appendices to the printed hearing record for S.341.

If you have any questions, please do not hesitate to call me at (202)789-1450. Thank you for your time and courtesy in this matter.

Sincerely,

Mona M. Janopaul

Mona M. Janopaul,
Attorney for the American Public Gas Association

COMMENTS OF THE
AMERICAN PUBLIC GAS ASSOCIATION
REGARDING S.341, TITLE X

The American Public Gas Association (APGA) represents publicly owned local gas distribution systems. APGA has over 350 members in 34 states, consisting of municipal gas systems, public utility districts, county districts, and other public agencies which own and operate gas distribution systems.

The vast majority of APGA members (like the vast majority - over 90% - of all LDCs) are "captive customers," i.e. they are served by only one interstate pipeline, and hence they do not operate in a "workably competitive" environment. In short, from the standpoint of the monopoly power of interstate pipelines vis-a-vis their LDC customers, the situation is the same today as when the Natural Gas Act (NGA) was passed in 1938 - indeed in some instances more perilous for ultimate consumers than before due to the various deregulation initiatives of Congress and the FERC itself.

SUMMARY

Overall, APGA agrees with the proposition that the present regulatory structure is overburdened and, hence, some rate and certificate matters are not being resolved in a timely manner. There are important components of S.341 which APGA supports. However, APGA cautions that some of the proposed changes in S.341 may work substantial injustice to the very consumers they are ostensibly designed to protect. Congress must not rush to judgment in the name of expedition without considering all the relevant factors. APGA believes that the Congress can act within the existing framework of the NGA both to make natural gas more readily available to the public and to encourage the public to use natural gas.

SEC. 10001(b)(1). CONSTRUCTION

Pipelines need to be given sufficient incentive and consumers sufficient protection to ensure that natural gas service to small municipalities and rural areas will at least continue at current levels. Left to their own devices, without the protection afforded by the NGA and administered by the FERC, pipelines will ignore the needs of small customers, and gas consumption could actually decrease in low load factor areas where service is not so lucrative for the pipelines.

Small LDCs require a mechanism through which they can avail themselves of firm transportation service, as well as sales service. It is only through such a mechanism that small customers can take advantage of the competitive market environment.

Notice must be provided to all communities within a wide radius of a proposed facility (e.g., 200 miles) in order that those communities can be aware of and have the option to avail themselves of such a new source of supply.

A forum must be provided to ensure that small customers will have access to a proposed new facility. That forum should be a national one (i.e., the FERC) in order to coordinate the nation's supply of natural gas.

SEC. 10001(b)(2). OPERATION

Provision must be made for small customers to have the opportunity to increase the volume of gas to be delivered by such new facilities. If this guarantee is not provided, as small communities grow and their need for fuel increases, they will be forced to consume other types of fuel.

SEC. 10001(d). RATE BASE TREATMENT

APGA supports the requirement that SEC. 10001(b) facilities be paid for by services associated with those facilities. However, APGA suggests that no "remission" be allowed after ten years, or at any subsequent time. Customers should not share the risk with the pipelines, just as the pipelines do not share their profits with the customers. If the pipeline wants some guarantee of recovery, it has the option of filing for a certificate under Section 7 of the NGA.

SEC. 10002. NGPA § 311 AMENDMENTS

APGA is strongly opposed to the changes proposed in this section. The "on behalf of" limitations have been litigated extensively at the FERC and in the courts. It is inappropriate for the Congress to step in at this juncture and change the results of all those evidentiary and judicial hearings.

APGA is also strongly opposed to opening up § 311 as a major avenue for construction. Pipelines have a current avenue (NGA Section 7 certificates, where recovery is regulated on a cost of service basis) and a proposed second alternative (SEC. 10001(b) deregulated construction, where the pipeline is at risk for recovery of its expenses). A third alternative, which effectively gives pipelines the best of both the regulated and deregulated options, is not in the public interest.

SEC. 10004. RATES AND CHARGES

APGA supports the proposed revisions to NGA Section 4 regarding period of notice (30 to 60 days) and enhanced refund protection for rate changes. However, the proposed revisions to NGA Section 4 do not appear to cover the situation where a pipeline files for a "restatement" of rates at the end of the standard three-year PGA cycle (versus a rate change). APGA provides proposed language to remedy this presumably inadvertent omission in the attachment hereto. See Attachment A.

If these amendments to NGA Section 4 are adopted, then concurrent amendments to NGA Section 5 must also be adopted in order to provide gas consumers with the equivalent protection that the proposed changes to NGA Section 4 are intended to provide. Currently, complaints lodged by customers under NGA Section 5 can only bring relief on a prospective basis - usually some years after the complaint is filed. Virtually no complaints are filed - not because there are no abuses warranting such complaints - but because of the time and cost and lack of effective relief associated with such complaints.

This glaring deficiency in complaint procedures also existed in the NGA's counterpart - Federal Power Act Section 206 - until

1988, when the Regulatory Fairness Act was enacted. Gas consumers are entitled to no less protection than electricity consumers, especially given the greater deregulation in the gas industries.

Attached to APGA's comments are its proposed revisions of NGA Sections 4 and 5. These proposed revisions are consistent with the clear intent of S.341 to provide gas consumers a forum for effective relief where deregulation leads to abuse by monopolists.

SEC. 10005. RULEMAKING

This section is either meaningless (because it gives the FERC no authority which it does not already have, see Mobil Oil Exploration & Producing Southeast, Inc. v. United Distribution Companies, 498 U.S. ___, 112 L.Ed.2d 636, 111 S.Ct. ___ (1991), or potentially cataclysmic (because it appears to invite generic abandonment authorization by the FERC). One of the most important protections afforded LDCs by the NGA is Section 7(b). That section guarantees that pipeline service to LDCs will not terminate at the end of the contract term absent a fact-specific showing of public convenience and necessity. No deviation from this standard should be entertained.

APGA COMMENTS ON
SENATOR BINGAMAN'S AMENDMENTS TO S.341

1. Environmental Contractors

APGA opposes this amendment which would allow an applicant to select the contractor who will prepare environmental documents in connection with the applicant's proposal to construct a NGA facility. This method would allow applicants to select whatever contractor they might feel would present their most favorable case regarding environmental review. Environmental review should remain an objective process, as it is intended to be under the NEPA.

APGA would prefer that the S.341 original method of having FERC select contractors be retained. However, APGA proposes an alternative method whereby contractors would be randomly selected by FERC (as one programs random selections of music from a list of songs). This would remove any delays in selecting a contractor, and keep the process an objective one.

2. Environmental Assessments

APGA is strongly opposed to this amendment, particularly since the above-mentioned amendment would allow the applicant to select its own contractor to prepare environmental assessments (EAs). While FERC Staff may not be as speedy as applicants may wish, Staff provides an object report in carrying out FERC's responsibilities under the NEPA. If FERC selects the contractor who prepares the

EA for the applicant, this might be a bit more palatable. However, the real solution here is, if the applicant wants an expedited process, then the applicant can file for a SEC. 10001(b), non-regulated pipeline. If the applicant wants the benefits and protections afforded to pipelines by constructing regulated facilities, then the applicant should be prepared to "endure" the full review necessary under the NGA and the NEPA.

3. Ex Parte Rules

APGA agrees that the application of *ex parte* rules to communications bewteen the FERC environmental Staff and other environmental agencies inhibits the exchange of information. APGA supports this amendment.

4. Unopposed Applications

APGA is strongly opposed to this amendment. It is well established that the role of the FERC (and its predecessor, the Federal Power Commission, FPC), "...does not permit it to act as an umpire blandly calling balls and strikes for adversaries appearing before it; the right of the public must receive active and affirmative protection at the hands of the Commission." *Scenic Hudson Preservation Conference v. FPC*, 354 F2d 608 at 620 (2nd Cir. 1965); *cert. denied*, 384 U.S. 941 (1966). Many applications are unopposed for a host of reasons, *e.g.*, because the public is not aware of them, is not able to fully analyze the potential impacts, or does not have the wherewithal to engage in a protest. The public does not have the experience that the FERC does with such applications, or the knowledge of related pending applications or pertinent information which might affect the application in question as does the FERC. Lack of opposition does not guarantee that an application proposes rates that are just and reasonable or a facility that will best serve the public interest. Again, if an applicant wants the benefits afforded to pipelines under the NGA, then the applicant must be willing to endure the necessary procedures offering protection to the consumers affected by that application. The FERC has the authority to order, and regularly has ordered, that proceedings be expedited or that a decision in an evidentiary hearing be ordered by date certain. If the applicant wants a speedier process, there is the non-certificated option of constructing a SEC. 10001(b) facility.

5. Replacement Facilities

This very issue was the subject of a recent FERC Rulemaking, RM90-1-000. In that proposed rule, FERC itself commented that the replacement of facilities may involve significant environmental impacts and should not be excused from the evidentiary hearing process. In its comments, APGA supported the FERC's proposed revisions to its Rules and Regulations which would require such projects to be subject to environmental compliance review. The Council on Environmental Quality noted that, "Under NEPA, all actions must be classified according to their potential to affect the quality of the human environment, not on the basis of project costs, protests, or other non-environmental factors." Congress should acknowledge the experience that FERC has gained from years of dealing with such situations by electing NOT to adopt this proposed amendment.

6. **Conclusive Need of Evidence**

Natural gas contractual commitments are never "conclusive evidence of need." Such contracts always carry sufficient caveats to allow one party or the other to bow out. Frequently, in an area presently not served by any natural gas pipeline, potential customers will sign commitments with more than one prospective pipeline in order to negotiate the best rate and to guarantee service with the one system that is eventually constructed. The Congress should not establish statutory presumptions based on such transient "commitments."

The Ashbacker Doctrine, established at the FCC, requires comparative hearings for competing proposals for certificated facilities. Again, if the applicant does not wish the delays inherently involved in a certificated proceeding, it is free to construct a SEC. 10001(b) facility. However, if the applicant wants the benefits of constructing a NGA Section 7 pipeline, then it should be prepared to prove that such a pipeline will be used and useful and in the public interest.

7. **Phased Certificate Proceeding**

Again, this issue was the subject of a recent FERC rulemaking, RM90-1-000. In that rulemaking, FERC proposed that certificate proceedings be phased, in much the same way as is proposed by this amendment. However, in its comments on phased proceedings, the Council on Environmental Quality dismissed the idea saying that the purposes of NEPA "cannot be achieved by adding environmental-review requirements onto agency decisions that have already been made and [after] choices among alternative courses of action have been effectively eliminated. And encouraging certificate applicants to seek financing and initiate contract negotiations prior to final decision makes them accomplices in the scheme to limit the choice of reasonable alternatives and reinforces the notion that, insofar as the commission is concerned, environmental review of NGA section 7 certificate applications is irrelevant." This amendment, too, should not be adopted.

8. **Procedure for Priority Natural Gas Facilities**

As with the Administration's proposal to abolish the FERC, this amendment would politicize the process of certificating pipeline facilities under the NGA. The criteria provided are so broad, that any natural gas facility could qualify for A, C, or D. Therefore, it becomes a matter of discretion of one person, the Chairman, as to which facilities are favored with the designation of "Priority." Again, the FERC has the authority to order that a proceeding be expedited, and a decision be issued by a date certain for NGA section 7 proceedings. If the applicant wants a speedier process, it is free to pursue construction under SEC. 10001(b). Congress should not eliminate procedural protections where the consumer will be the one to pay. If Congress wants more natural gas to be consumed, it must maintain the NGA's protections for the natural gas consumer.

9. Non-jurisdictional Facilities

APGA supports this amendment as a necessary clarification of the NGA. This amendment would better establish the demarkation between jurisdictional and non-jurisdictional facilities, such that FERC will be better able to determine its responsibilities.

APGA COMMENTS ON THE ADMINISTRATION'S PROPOSED ELIMINATION OF THE FERC

Eliminating FERC in favor of an administrator at the Department of Energy would be contrary to the public interest. The FERC has been charged by Congress in the Natural Gas Act to protect gas consumers from exploitation by interstate pipelines, and the FERC's ability to accomplish this charge depends in large measure on it being an independent regulatory agency free of political pressures. To "politicize" the process by supplanting FERC with a single person responsible to the President would undermine the fundamental guarantees that are embodied in the Natural Gas Act. Results would depend on political clout rather than the merits of a particular controversy.

APGA joins those who seek to expedite various certificate and other proceedings before the FERC, and supports legislation to effect that result. But APGA urges that Congress not forsake the due process rights of those intended to be the beneficiaries of the Natural Gas Act in the name of expedition. APGA reserves the right to make comment upon other provisions of the Administration's NES at the appropriate time. However, since the Administration's proposal to abolish FERC was discussed at the hearings on S.341, and because APGA strongly opposes this proposal, APGA has taken this opportunity to comment on this one provision at this time.

Attachment
page 1 of 4

NGA SECTION 4 AND 5 AMENDMENTS

[Additions and deletions noted for Section 4, 15 U.S.C. 717c, are from Section 4 as currently existing. Additions and deletions noted for Section 5, U.S.C. 717d, are from Section 206 of the Federal Power Act, 16 U.S.C. § 824e, as currently existing. All additions are underlined, and all deletions are noted by brackets.]

§ 717c. Rates and charges.

(a) Just and reasonable rates and charges. All rates and charges made, demanded, or received by any natural-gas company for or in connection with the transportation or sale of natural gas subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges, shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.

(b) Undue preferences and unreasonable rates and charges prohibited. No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rates, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

(c) Filing of rates and charges with Commission; public inspection of schedules. Under such rules and regulations as the Commission may prescribe, every natural-gas company shall file with the Commission, within such time (not less than sixty days from the date this Act takes effect) and in such form as the Commission may designate, and shall keep open in convenient form and place for public inspection, schedules showing all rates and charges for any transportation or sale subject to the jurisdiction of the Commission, and the classifications, practices, and regulations affecting such rates and charges, together with all contracts which in any manner affect or relate to such rates, charges, classifications, and services.

(d) Changes in rates and charges; notice to Commis Unless the Commission otherwise orders, no change sh made by any natural-gas company in any such rate, classification, or service, or in any rule, regul contract relating thereto, except after [] sixty days' notice to the Commission and to the public. Such notice shall be given by filing with the Commission and keeping open for public inspection new schedules stating plainly the change or changes to be made in the schedule or schedules then in force and the time when the change or changes will go into effect. The Commission, for good cause shown, may allow changes to take effect without requiring the [] sixty days' notice herein provided for by an order specifying the changes so to be made and the time when they shall effect and the manner in which they shall be filed and published.

(e) Authority of Commission to hold hearings concerning new schedule of rates. Whenever any such new schedule is filed the Commission shall have authority, either upon complaint of any State, municipality, State commission, or gas distributing company, or upon its own initiative without complaint, at once, and if it so orders, without answer or formal pleading by the natural-gas company, but upon reasonable notice, to enter upon a hearing concerning the lawfulness of such rate, charge, classification, or service; and, pending such hearing and the decision thereon, the Commission, upon filing with such schedules and delivering to the natural-gas company affected thereby a statement in writing of its reasons for such suspension, may suspend the operation of such schedule and defer the use of such rate, charge, classification, or service, but not for a longer period than five months beyond the time when it would otherwise go into effect; and after full hearings, either completed before or after the rate, charge, classification, or service goes in effect, the Commission may make such orders with reference thereto as would be proper in a proceeding initiated after it had become effective. If the proceeding has not been concluded and an order made at the expiration of the suspension period, on motion of the natural-gas company making the filing, the proposed change of rate, charge, classification, or service shall go into effect; provided, however, that any restatement of a rate filed with the Commission by a natural-gas company shall be deemed to be a proposed change of rate for purposes of this section. Where [] rates or charges are thus made effective, the Commission may, by order, require the natural-gas company to furnish a bond, to be approved by the Commission, to refund any amounts ordered by the Commission
to keep accurate accounts in detail of all amounts receiv
[], specifying by whom and in whose behalf such amounts w
paid and, upon completion of the hearing and decision
order such natural-gas company to refund, with interest
portion of such [] rates or charges by its decision fou
justified. At any hearing involving a rate or charge
to be [] changed, the burden of proof to show that the
or charge is just and reasonable shall be upon the

gas company, and the Commission shall give to the hearing and decision of such questions preference over other questions pending before it and decide the same as speedily as possible.

§ 717d. Power of Commission to fix rates and charges; determination of cost of production or transportation.

(a) Decreases in rates. Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification, demanded, observed, charged, or collected by any [] natural-gas company for any [] transportation or sale of natural gas subject to the jurisdiction of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order: Provided, however, That the Commission shall have no power to order any increase in any rate contained in the currently effective schedule of such natural-gas company on file with the Commission, unless such increase is in accordance with a new schedule filed by such natural-gas company; but the Commission may order a decrease where existing rates are unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates. Any complaint or motion of the Commission to initiate a proceeding under this section shall state the change or changes to be made in the rate, charge, classification, rule, regulation, practice, or contract then in force, and the reasons for any proposed change or changes therein. If, after review of any motion or complaint and answer, the Commission shall decide to hold a hearing, it shall fix by order the time and place of such hearing and shall specify the issues to be adjudicated. The Commission shall render its decision, including therein its reasons for such decision, on whether to hold a hearing upon a complaint within 60 days after the filing of such complaint.

(b) Refund authority. Wherever the Commission institutes a proceeding under this section, the Commission shall establish a refund effective date. In the case of a proceeding instituted on complaint, the refund effective date shall not be earlier than the date 60 days after the filing of such complaint nor later than 5 months after the expiration of such 60-day period. In the case of a proceeding instituted by the Commission on its own motion, the refund effective date shall not be earlier than the date 60 days after the publication by the Commission of notice of its intention to initiate such proceeding nor later than 5 months after the expiration of such 60-day period. Upon institution of a proceeding under this section, the Commission shall give to the decision of such proceeding the same preference as provided under Section [] 4 of this Act and otherwise act as speedily as possible. If no final decision is rendered by the refund effective date or by the conclusion of the 180-day period commencing upon initiation of a proceeding pursuant to this section, whichever is earlier, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision. In any proceeding under this section, the burden of proof to show that any rate, charge, classification, rule, regulation, practice, or contract is unjust, unreasonable, unduly discriminatory, or preferential shall be upon the Commission or the complainant. At the conclusion, of any proceeding under this section, the Commission may order the [] natural-gas company to make refunds of any amounts paid, for the period subsequent to the refund effective date through a date fifteen months after such refund effective date, in excess of those which would have been paid under the just and reasonable rate, charge, classification, rule, regulation, practice, or contract which the Commission orders to be thereafter observed and in force: Provided, That if the proceeding is not concluded within fifteen months after the refund effective date and if the Commission determines at the conclusion of the proceeding that the proceeding was not resolved within the fifteen-month period primarily because of dilatory behavior by the [] natural-gas company, the Commission may order refunds of any or all amounts paid for the period subsequent to the refund effective date and prior to the conclusion of the proceeding. The refunds shall be made, with interest, to those persons who have paid those rates or charges which are the subject of the proceeding.

[]

[] (c) Costs of production and transportation. The Commission upon its own motion, or upon the request of any State commission whenever it can do so without prejudice to the efficient and proper conduct of its affairs, may investigate and determine the cost of the production or [] transportation of natural gas by a natural-gas company in cases where the Commission has no authority to establish a rate governing the sale of such [] natural gas.

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Sunrise, Florida

April 12, 1991

VIA HAND DELIVERY

Donald F. Santa, Jr., Counsel
United States Senate Committee
on Energy and Natural Resources
364 Dirksen SOB
Washington, D.C. 20510

Re: Senator Wirth's "Gas Policy Reform Act," S.662, and "National Energy Efficiency and Development Act," S.741 and S.742; and the Administration's "National Energy Strategy Act," S.570.

Dear Mr. Santa:

On March 19, 1991, the American Public Gas Association (APGA) submitted a prepared statement for the Committee's hearing record regarding Title X of S.341 (the "National Energy Security Act of 1991"), certain amendments proposed by Senator Bingaman thereto, and the Administration's proposal to abolish the Federal Energy Regulatory Commission (FERC). In that statement, the APGA reserved the right to make further comment as the need arose. This supplemental statement provides the APGA's views on the regulatory issues and "accelerated pipeline construction" provisions of S.662, S.741 and S.742 (hereinafter collectively referred to as S.662) and the natural gas title of S.570.

I.

S.662, the "Gas Policy Reform Act"

APGA shares the concerns regarding S.662 expressed by Mr. Ronald J. Binz, on behalf of the National Association of State Utility Consumer Advocates (NASUCA), in his testimony before the Committee. It is not clear to APGA that the provisions of this bill will meet its stated goal, to "increase the use of natural gas in the United States," but may in fact decrease the use of natural gas because it will lead to increased rates for small customers, arbitrary abandonment of service, and the shifting of the risk to natural gas customers of cost responsibility for uneconomic pipeline facilities.

Mr. Wirth was quoted in the "Gas Daily" on March 15, 1991, and in "The Energy Report" on March 18, 1991, as saying that past attempts to reform gas regulation have been stymied by "controversy between segments of the gas industry, each looking after its own interests." S.662 certainly would resolve a number of controversies, but all in favor of the pipelines! Controversies concerning pipeline monopoly service should be left to resolution before the appropriate regulatory body, FERC, where all segments of the natural gas industry and consuming public can make their interests known.

Mr. Wirth was also quoted in those same articles as having said that "[t]he complicated adversarial regulatory system we have built up for regulating gas over the years has, in effect, kept gas from the people who need it." In truth, though, this regulatory the system has required pipelines to provide and maintain service to numerous small customers in many circumstances where the pipelines were otherwise unwilling to initiate or continue such service.

Provisions of S.662 would unfairly shift costs and risks to customers through changes in rate design and would mandate the automatic "as-billed" flowthrough of producer demand charges to customers. Monopoly pipeline companies would be permitted to extract higher rates of return from firm services, and would be able to arbitrarily abandon sales service. Moreover, rather than increasing competition by encouraging new investors to construct pipelines, S.662 provides unfair advantages for existing pipeline companies. Thus, pipeline companies will be protected from both competition from new entrants and the risk of their investments.

The captive natural gas customer, unlike the long distance telephone customer, does not have the physical capability to chose among a plethora of long distance interstate pipelines. Even if the construction of new pipelines is encouraged by this proposed legislation, these pipelines would be located in the production area and would not extend to the city gates of the great majority of natural gas distribution systems. Small distributor-customers have one, and only one, source of pipeline capacity to obtain their required gas supplies -- the pipeline that was required by the FERC (and before it, by the FPC) to serve their respective communities with firm sales service. Small customers do not have bargaining power, or storage facilities, or true market access. The pipelines which serve small distributor-customers are still monopolies, and these customers must be protected from the abuse inherent in monopoly service. Just as many small towns either no longer have airline service or now pay exorbitant fares for such service, and just as many small communities are losing their bankrupt banks, S.662 would lead to both increased rates and the loss of natural gas service to many small communities.

II.

S.570, the "National Energy Strategy Act" (NES)

This bill goes far beyond either S.341, S.662, or H.R.779 (Representative Sharp's "Natural Gas Enhancement Act of 1991"), towards deregulation of the natural gas industry. While it attacks one derivative facet of Natural Gas Act (NGA) Section 7 proceedings, i.e., the opportunity for competitors to participate in such proceedings, it ignores the fundamental purpose of such NGA proceedings, i.e., the opportunity for natural gas distributor-customers and consumers to be heard in an objective forum regarding proposed pipeline construction and rates since they will be the ones to receive (or be denied) service from and to pay the costs of the facilities to be constructed. The NGA was enacted to protect the public interest and to ensure that natural gas facilities, for which the public would have to pay, would be necessary to serve the public and would be "used and useful." In this crucial aspect, the industry has not significantly changed since the NGA was enacted because most pipelines still have monopoly power over most customers. Customers still need the protections offered by the NGA, but S.570, unfortunately, would effectively eliminate those protections.

Contrary to the contentions of the Administration, service and construction under Section 311 of the Natural Gas Policy Act (NGPA) is hardly "adrift" in uncertainties. As noted in APGA's initial comments, the breadth of the "on behalf of" standard has been thoroughly litigated at FERC and in the courts, where all factions of the industry had full and fair hearings. To change this standard now would introduce uncertainty, and lead to further litigation. As for allowing major construction under section 311, APGA also stated its opposition in its initial comments. APGA agrees with the comments of the Natural Gas Supply Association (NGSA) that such a broadening of construction authority under Section 311 is not necessary (since the NGA Section 7 regulated option already exists and assuming there will be a deregulated option of some kind included in any natural gas legislation enacted by this Congress) and inappropriate (because the pipeline will get the benefit of regulation, i.e., shared risk of costs, while not having to submit to regulatory approval through proof that construction is necessary and in the public interest).

APGA strongly opposes those portions of S.570 which would provide for optional certificate procedures and nonjurisdictional certificate procedures. The optional certificate procedures proposed in S.570 do not include the protections and procedural safeguards afforded by those proposed in S.341. Again, nonjurisdictional pipelines are out of the question given the current status of the industry. Small distributors and consumers must be protected from the monopoly power of the pipeline that is physically connected to their town. Deregulation may encourage construction of pipelines in the production area, but more pipelines will not be built to small towns where the market is less lucrative. Section 7(a) of the NGA was written because pipelines have historically been unwilling to even provide sales service to small towns, let alone competitive transportation service.

APGA could support the provisions in S.570 regarding mandatory interconnection if they were properly conditioned. It should be clarified that the notice and hearing procedures of existing Section 7(a) would apply to mandatory interconnection actions. The petitioner for mandatory interconnection should be required to bear all associated costs related to the relevant interconnection. And, if Section 7(a) is to be amended, it should be broadened to include transportation service as well as sales service. Any new version of Section 7(a) must require that mandatory interconnections meet the existing statutory standards of not creating any undue burden or an impairment of existing services.

Finally, APGA reemphasizes that it is strongly opposed to the abolishment of FERC, as fully stated in its initial comments.

APGA thanks the Committee for this opportunity to present its views. APGA reserves the right to comment further as the need arises. If there are any questions, please do not hesitate to call me.

Sincerely,

Robert S. Cave

Robert S. Cave
Executive Director

cc: All Members of the Committee on Energy and Natural Resources, U.S. Senate
Stanley W. Balis, Esquire

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

April 8, 1991

OFFICE OF THE COMMISSIONER

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
APR 8 - 1991
WASHINGTON, D.C. 20510

Honorable J. Bennett Johnston
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510-6150

re: Title X, Energy Security Act of 1991 (S. 341) and proposed amendments introduced by Senator Bingaman and the National Energy Strategy Act (S. 570)

Dear Chairman Johnston:

I sincerely appreciate your letter of March 7, 1991 inviting my comments on the above referenced proposed legislation. I would also like to take this opportunity to commend the efforts of both you and Senator Wallop in sponsoring (S. 341) which demonstrates your individual commitments and concerns for the energy sector so vital to the Nation's economy.

Although I have not completed a detailed analysis of the proposed legislation, I would like to offer these first impressions. I would concur with the notion expressed in the testimony submitted by the Commission's staff on March 7, 1991 as amended on March 29, 1991, that the above-referenced proposed legislation, as well as H.R. 779, all seek to build upon the pro-competitive gas market that began in Congress with the enactment of the NGPA of 1978 and which FERC has attempted to foster in the past six years.

I concur completely with the legislative interest in streamlining the pipeline certificate process. While I believe that flexible economic options for market participants are the linchpin of a competitive natural gas market, the natural gas industry is still in the midst of a competitive transition. Until such time as truly comparable service options are in place to curb the natural and historical monopoly power of the pipelines, I am concerned that the significant elimination of regulatory oversight may pose some difficult problems. The questions raised by staff regarding, in particular, the non-jurisdictional construction option are on point.

In general, the Commission staff report was an accurate representation of both our on-going efforts to resolve some of the transitional problems the industry is facing and of my concerns vis-a-vis the proposed legislation. I support the staff response.

As I become more familiar with the proposed legislation I would be pleased to have the opportunity to express my views.

Sincerely,

Jerry J. Langdon
Commissioner

cc: Senator Malcolm Wallop
Ranking Republican Member
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510-6150

AGD

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Prepared Statement Of

ASSOCIATED GAS DISTRIBUTORS

Submitted to the

UNITED STATES SENATE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

on S. 341 --

NATIONAL ENERGY SECURITY ACT OF 1991

March 14, 1991

The Associated Gas Distributors (AGD) is a group of 41 natural gas distribution companies which provide gas utility service to consumers in Southern California and along the East Coast. As State or locally regulated public utilities, the AGD members approach federal energy policy issues affecting natural gas with a unique perspective. These companies are not free to "pick up their pipes" and move to some more profitable location. They are, instead, inextricably bound to the local areas and economies wherein they serve.

Unlike gas producers, marketers, brokers and large industrial users, the AGD members are _regulated_ public utilities. They have obligations at the State and local level which transcend, both as a legal and practical matter, the obligations of _any other_ segment of the gas industry. Unlike interstate pipeline companies, which are for the most part regulated by the Federal Energy Regulatory Commission (FERC or Commission), the AGD members are _not_ directly regulated by FERC, but _are_ directly and significantly affected by the policies and rules established there.

AGD agrees that there is a great deal that can be done to streamline the federal natural gas regulatory structure. Indeed, some revisions to that structure are essential to permit the industry to meet the demands of the marketplace for natural gas. Air quality concerns, undue reliance on imported oil, balance of payments and efficient use of energy all point to a more expanded role for the direct use of natural gas in the Nation's energy consumption mix. Gas utilities and the infrastructure they command stand ready, willing and able as the critical link to the retail marketplace to rise to that occasion.

Legislative initiatives, such as S. 341, hold the promise of removing some of the unnecessary and burdensome institutional barriers to natural gas reaching its full potential. By and large, these initiatives are welcome and long overdue. The key to public policy success on these initiatives is to maintain a sense of equilibrium or balance.

Fundamental systemic changes are necessary. And, it is equally necessary that the embedded benefits of the gas utility infrastructure be retained and nurtured to an even greater potential betterment of society. Thus it is that AGD urges the Committee throughout this prepared statement to weigh carefully the implications of its actions on the gas utility segment of the industry and the millions of consumers served thereby. It would be ironic indeed if the well-intended initiatives of today are permitted to so obscure and undermine the benefits of the present system that those benefits are lost for naught.

COMMENTS ON

TITLE X OF S. 341

Section 10001 -- Optional Construction Procedures. AGD generally supports the optional procedure for construction of natural gas transportation facilities as drafted in § 10001. Several key features of § 10001 are essential and should be retained and, in some respects, clarified. First, the power of the Federal Energy Regulatory Commission to attach reasonable terms and conditions to the operating certificate, as set forth in paragraph (b)(2) will presumably provide an opportunity for affected parties to obtain Commission redress on matters which adversely impact their interests. It should be made clear that the Commission's conditioning power will be available at least to address issues related to impairment or degradation of service to existing pipeline customers, oversubscription of capacity, subsidization of the new service by third-parties and bypass of local distribution companies (LDC).

Second, the 10-year prohibition on allocating costs of the facilities to other services of the company, § 10001(d), properly seeks to shield third-parties from costs for which they are not responsible. This is in accordance with traditional cost responsibility concepts and should be retained. It may be advisable also to consider a more flexible cost allocation procedure whereby costs could, upon a proper showing, be allocated differently to account for changes in the usefulness of the service over time, though still within the 10-year period.

Third, subparagraph 10001(c)(1)(iv) provides that rates for the facility shall be "stand-alone and incremental." This seems to imply that rates would be "cost-based" as well, even though subparagraph 10001(c)(1)(iii) provides that an agreement between the company and a person who contracts for transportation service "may constitute a rate schedule." There appears to be an ambiguity here which should be clarified to assure that rates are "cost-based," that is, based upon booked cost of service data. This is an especially important notion given that in most circumstances pipeline/facilities capacity is now, and is likely to remain in the future, a monopoly product which the competitive give and take of market participants is unlikely to mitigate.

Fourth, the provision for application of NGA § 5 to rate revisions, as stated in paragraph 10001(c)(3), is a necessary and proper safeguard against unjust, unreasonable, unduly discriminatory or preferential rates and service. In terms of perfecting this provision to make it more useful as a practical matter, AGD recommends that reasonably prompt deadlines be included as to Commission action on any complaints as well as any further Commission remedy developed pursuant to a complaint. The present and future dynamics of the natural gas marketplace need an equally dynamic and efficient process for resolving complaints in a timely, and therefore effective, manner. A complaint process which six months or more after the fact finds that a marketer, broker, producer, industrial user, LDC or other shipper should have been permitted to move gas six months earlier is simply not an effective remedial process.

Finally, § 10001 appears by its terms to be limited to facilities "to provide transportation service," § 10001(b)(1), as opposed to facilities which provide transportation or sales service. It is certainly true that pipeline transportation of gas owned by others has become the dominant portion of pipeline throughput in recent years. By the same token, however, a substantial portion of throughput remains pipeline sales volumes, and there does not appear to be any particularly sound public policy rationale for excluding facilities for sales service from the optional procedures section. To the contrary, sales service continues to play a critical role for most LDCs as a part of a portfolio of gas supplies necessary to serve retail markets. Accordingly, AGD suggests that § 10001 be revised to include facilities for the transportation or sales of gas.

Section 10002 -- NGPA § 311 Transportation. NGPA § 311 was originally intended to facilitate access by the pre-1978 "interstate" gas markets to "intrastate" gas supplies. Its use has quite obviously expanded, and substantially so, beyond that original intent. In many respects this development has been favorable, e.g., constructive competition has been enhanced, alternative supply arrangements have been developed and more quickly consummated, throughput has been increased and market efficiencies have been gained. These positive developments have not, however, been without costs, e.g., impairment of service to existing customers and, in the case of LDC bypass, higher costs for most consumers (generally residential, commercial and industrial users not able to hook-up directly to a pipeline), stranded LDC investment and redundant pipeline facilities. A reasonable course for public policy at this juncture in terms of "fine-tuning" § 311 would seem to be one which optimizes the positive contributions produced by § 311 and minimizes the "downsides."

As drafted, the revision to § 311 set forth in § 10002 does optimize the benefits by expanding the class of § 311 users to include "any other person." Unfortunately, § 10002 is asymmetrical. It does nothing to minimize adverse consequences, and, indeed, it exacerbates those consequences because of its one-sidedness in merely expanding its application to "any other person."

AGD supports the expansion of the "class" of § 311 users so long as this revision is accompanied by reasonable safeguards to minimize adverse consequences associated with impairment of service to existing customers and LDC bypass. We submit that the public utility obligations of LDCs and, perhaps more importantly as a practical matter, retail market reliance on LDCs and their utility system infrastructure warrants these reasonable safeguards.

More specifically, AGD suggests that the revised § 311 service be accompanied by an *expedited prior notice and protest procedure limited to claims of impairment of service to existing customers and LDC bypass*. If no protest is filed within a short period after public notice, say, 14 days, the § 311 service would proceed. *If a protest is filed on impairment of service grounds, the Commission would resolve it expeditiously through summary procedures. If a protest is filed on grounds of bypass, the Commission would be empowered to grant or deny the § 311 service depending upon whether the affected LDC is ready, willing and able to provide service on terms and conditions prevailing under applicable State or local regulation*.

The above-explained impairment of service safeguard is necessary to assure that existing customers already using *and relying* on their rights or entitlement to pipeline capacity will not have their rights diminished or degraded by the new service. Some reasonable "check" for existing users seems fair given the equitable position of those users on a "first come, first served" rationale, their reliance on their present service entitlements and, in the case of LDCs, their utility obligation and retail market reliance on their service.

The bypass safeguard is intended to provide some reasonable measure of harmony with and deference to State law. If an LDC is doing all it is authorized to do under applicable State or local regulation, then that LDC is competing as best as it can. And, if in spite of the LDC's best "competitive" efforts, the bypassing industrial user, for example, wants a "better deal," it has a forum where it can present its case for that relief -- the applicable State or local regulatory body.

The implications of bypass can be very significant both in terms of direct and indirect costs to the remaining LDC customers. Granted that the direct costs of staying on the LDC system may be higher for the large industrial user than bypassing the LDC for direct pipeline service, this represents, however, precisely the kind of issue which is best left to the State and local regulatory bodies to assess. Only at that level of government can the full facts, circumstances and implications to all parties (the industrial user, the residential, commercial and industrial users that cannot bypass the LDC, and the LDC) be developed, analyzed, weighed and decided consistently with the economic development, environmental and energy policy desires and objectives of those most affected. AGD strongly urges the modification of § 10002 to provide the foregoing minimum impairment of service and bypass safeguards.

Section 10003 -- NEPA Compliance. AGD endorses and supports these provisions for streamlining and expediting the environmental review process by designation of FERC as the "lead" agency for preparation of environmental documents and by requiring the Commission to permit the applicant, at its expense, to choose a third-party contractor to prepare the necessary environmental documents. These revisions are a major improvement over the status quo because of both procedural efficiencies gained and potentially greater resources applied.

Section 10004 -- Rates and Charges. AGD supports the revisions to NGA §§ 4(d) and (e) which extend the notice period for rate changes from 30 to 60 days and clarify that the burden of proof for rate increases or decreases remains with the pipeline applicant for a rate change. While these modifications are useful (excepting any provision for "retroactive" refunds, which AGD opposes), further amendments to NGA § 4 are necessary to assure a fairer rate setting process by reducing the inequities in present law which result in disproportionate pipeline leverage over its customers, sales and transportation alike. Thus, AGD recommends that § 4 be amended to remove the rate-filing suspension period and replace it with a requirement that:

(1) no rate change shall be effective until approved by FERC;

(2) FERC shall issue a final order approving or disapproving any filed rate within 12 months of such filing; and,

(3) no rate change may be filed while a prior rate change is pending before FERC.

Under NGA § 4, interstate pipelines have the virtually unfettered right to file for rate increases at any time. The NGA imposes no limit on the amount of such rate increases or their frequency. The Commission may suspend the effectiveness of the rate filing for five months, after which it becomes effective on motion of the pipeline subject to refund (in the case of a rate increase) unless the Commission has finally ruled on the rate filing during the five-month suspension period.

This system of rate regulation places pipeline customers at a distinct disadvantage. As a practical matter, few rate cases are resolved by Commission order within the five-month period. Customers who object to a filed rate are thus put in an untenable position. On the one hand, they may engage in meaningful and time-consuming settlement negotiations or litigation and allow the filed rates to go into effect, thereby subjecting their markets to higher, unjust and unreasonable rates and jeopardizing those markets. Or, on the other hand, they may be driven to a less than favorable settlement within the five-month suspension period to avoid the market disruption which would arise if the rates went into effect as filed.

Pipelines are well aware of the bargaining leverage they have over their customers in this respect, and they take full advantage of their statutory rate-filing and rate-setting prerogatives, to the clear detriment of customers. The customers' refund "remedy" is simply not an effective deterrent here because market loss cannot be remedied by refunds. Further, even though refunds may have to be made by the pipeline, the fact remains that the pipeline has collected the funds from its customers during the pendency of the rate case which may take two, three or more years. Even with interest on refunds, this rate collection system represents an attractive method of forced "borrowing" of capital from customers. The problem is exacerbated further by the fact that there is no proscription on how many rate cases a pipeline may have pending at any one time. This "pancaking" of rate increase filings can literally overwhelm the Commission and the pipeline customers.

From a pipeline customer perspective, the pipeline rate collection system is broken and should be fixed in this legislation. The need is clear. Pipeline rate increases for sales and transportation services can have severely debilitating consequences on the ability of producers, marketers, brokers, end-users and LDCs to meet demands for gas at competitive prices. Moreover, there is no good reason for maintaining the present system when a viable, fairer system is available.

The practicality of AGD's recommendation is emphatically demonstrated by state agency experience. State public utility commissions around the country routinely process large and complex cost of service rate cases under methods very similar to the method proposed here by AGD, that is, required Commission action on a rate filing in one year or less, no collection of filed rates until approved, and no "pancaking" of rate filings. This

no. of parties, complexity of issues?

is hardly a "radical" or novel approach to the rate-setting process. There may well be some modifications to the form and content of pipeline rate filings to make this system work efficiently, e.g., more descriptive detail as to the specific changes in pipeline costs of service necessitating the rate increase; more comprehensive explanations of the need for the rate change, etc. But, these are relatively minor implementing features which would flow naturally from the system proposed here.

AGD strongly urges the Committee to take this opportunity to adopt meaningful revisions to the NGA § 4 rate-setting process. Today that process is designed for delay and tilted grossly in favor of the pipeline. Fundamental fairness, efficiency and the enhanced competitive nature of the gas industry demand a better rate-setting process. No "pancaking" of rate filings, no collections until approved and required Commission action in a year or less are workable improvements which should be adopted.

Section 10005 -- Rulemaking Procedures. AGD does not object to this amendment to the DOE Organization Act which appears essentially to codify existing law. See, e.g., Panhandle Eastern Pipe Line Co. v. FERC, slip op. at 5-6 (D.C. Cir. June 29, 1990). So long as the substantive NGA standards covering the issuance of certificates of public convenience and necessity and the authorization of abandonment remain unchanged, proceeding by rulemaking, as opposed to case-by-case adjudication in all instances, may reasonably expedite Commission decision-making.

Section 10006 -- Review of Commission Orders. AGD endorses all NGA and NGPA revisions made in § 10006 with respect to deadlines for Commission action on rehearing applications and to abbreviating and streamlining the initial court review process. These are reasonable, workable modifications which expedite decision-making without prejudice to due process considerations. A timely, final decision, whether favorable or not, at least provides parties with a measure of certainty as to the ground rules affecting business decisions and thereby facilitates private sector efficiencies.

The rehearing stage of FERC decisions is often problematic in terms of promptness of final action. There are, however, other critical points in the FERC, NGA/NGPA decision-making process which are equally problematic. These administrative "bottlenecks" occur at the Administrative Law Judge (ALJ) initial decision juncture, at the Commission level on review of ALJ decisions and at the Commission level on matters where an ALJ decision is not involved. An unintended and unfortunate consequence of the § 10006 deadline for FERC action on rehearing applications may be to increase delay at these other key points in the Commission's decisional process if the Commission tries to "compensate" for the loss of time which would otherwise be available to it.

AGD strongly urges this Committee to go a step further and establish deadlines for ALJ initial decisions in adjudicated *cases, for Commission action on review of ALJ initial decisions and for Commission action where no ALJ decision is required*. A reasonable deadline for initial decisions would be 120 days after the close of the hearing record, a reasonable deadline for Commission action on review of an initial decision would be 120 days after the initial decision, and a reasonable deadline for Commission action on matters where no ALJ decision is involved would also be 120 days.

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This additional step is necessary and proper for several reasons. First, it addresses known administrative "bottlenecks" in the decision-making process and would thereby expedite decision-making. Second, it addresses an unintended, but probable consequence of the § 10006 rehearing deadline, *i.e.*, simply moving delay back further down the line of decision-making. And, third, competitive markets are more efficient with timely governmental decisions where such government intervention obtains.

Section 10007 -- Antitrust Relief. AGD supports the limited antitrust relief provided in this section for independent producer cooperatives *with the proviso that the exclusion of otherwise qualified pipeline and LDC affiliates be removed*. Section 10007 should facilitate the formation of producer cooperatives which would in turn facilitate the development of supply sources that are more attractive and therefore more readily marketable to LDCs.

The section applies only to groups of "independent producers," a term defined as any person whose natural gas production does not exceed 6 million cubic feet per day and is not an affiliate of a pipeline or LDC. AGD submits that the most pertinent indicia here of ability to market gas is the amount of production controlled, not corporate affiliation. The central notion of this section is that cooperative ventures by smaller producers will enable those producers more readily to market their product. If LDC production affiliates which would otherwise qualify by size of production are excluded from such cooperative ventures, the ability of the venture to develop more marketable increments of gas is diminished proportionately.

If the affiliate exclusion is premised on a concern about "sweetheart" deals between affiliates, the Committee should be aware that LDC purchases from their production affiliates are probably more rigorously scrutinized (by state regulatory authorities) than purchases from nonaffiliates. The spectre of a detailed, "20/20 hindsight" review of such transactions by State public utility commissions reinforces arms-length bargaining with affiliates and is itself more than sufficient reason to treat such affiliates as nonaffiliate producers for purposes of cooperative marketing ventures.

Section 10008 -- Vehicular Natural Gas (VNG) Jurisdiction. AGD strongly endorses the clarification of the scope of federal jurisdiction as set forth in § 10008 with respect to VNG activities of LDCs and NGA § 7(f) companies. Natural gas vehicles (NGV) are one of the most promising markets for the gas industry and should be encouraged in every way. The favorable clarification of "hypertechnical," unintended legal impediments to the full development of VNG, as in § 10008, is an eminently sensible and essential strategy to nurture and promote VNG. It is rare indeed for natural gas legislation to be truly noncontroversial, but § 10008 is such a situation.

NGVs present an almost unparalleled opportunity for the country and for all elements the gas industry. Wide-scale NGV use can improve air quality, reduce reliance on oil imports, reduce the country's balance of payments, optimize efficient energy consumption through direct use of natural gas, increase markets for all segments of the gas industry, and maximize utilization of the industry's production, transmission and distribution infrastructure. Section 10008 contributes to the realization of these objectives and should be adopted.

COMMENTS ON
SENATOR BINGAMAN'S AMENDMENTS

Senator Bingaman has proposed a series of amendments to the natural gas title of S. 341. The objective of the amendments is to streamline further the traditional NGA § 7 certificate process. With all due respect to other, more novel approaches to increase the efficiency of the natural gas regulatory process, AGD commends Senator Bingaman's focus on the NGA § 7 certificate process and supports all of his amendments. Minor, technical revisions to a few of those amendments would produce even more useful improvements in the process, and we recommend the Committee's consideration of those revisions as described below.

1. Environmental Contractors. This is a positive, perfecting amendment to § 10003(b) of S. 341 in that it allows the applicant's selection of a third-party environmental contractor from a list of such contractors designated by FERC, as opposed to using a single FERC-selected contractor.

2. Environmental Assessments (EA). Requiring FERC to permit an applicant-prepared EA is reasonable given the higher probability of necessary resource being timely applied and the inherently preliminary nature of an EA.

3. Ex Parte Rules. It is appropriate that consultative dialogue between federal agencies in the NEPA process not be governed by ex parte rules. Though not addressed by this amendment, the issue of consultative dialogue among FERC commissioners is an appropriate subject for the Committee's review as well. FERC is intended to be a "collegial" body. Yet, the "Sunshine Act" requirements make it very difficult for the commissioners themselves to engage in the kind of open and frank exchanges of opinion that are commonly held among colleagues. The Sunshine

Act may operate to drive these kinds of discussions to the staff, rather than commissioner, level, and it may thereby overly inhibit the Commission's capacity to function efficiently. Obviously the Commission should not be excluded in all respects from the Sunshine act, but *AGD respectfully suggests that the Committee consider some carefully crafted mechanism to facilitate a reasonable measure of private, collegial discourse among FERC commissioners*.

4. *Unopposed Applications*. AGD heartily endorses this amendment and suggests that it be expanded somewhat to *provide for a project proceeding as unopposed even where a protest is filed in the 60-day period if that protest is withdrawn or otherwise resolved within 30 days following the 60-day notice period*. It may well be that a protest was interposed because of a misunderstanding about some aspect of the project or that the protesting party and the applicant can readily resolve any issue which triggered the protest. In such cases, the project should be permitted to proceed as "unopposed."

5. *Replacement facilities*. AGD supports this codification of historic Commission practice. *See* 18 C.F.R. § 2.55(b).

6. *Conclusive Evidence of Need*. AGD members have experienced delays in fully subscribed FERC projects because of the presence of "competing" applications which did not have such customer support. There is no good reason for delays of this sort,

and AGD accordingly supports the amendment as a reasonable response to the so-called Ashbacker issue and as an appropriate way to deal with "spoiler" projects.

7. Phased Certificate Proceedings. AGD supports this amendment as a reasonable expediting measure.

8. Priority Procedures. AGD supports this technique for procedural expedition on the understanding that substantive NGA standards remain applicable to such projects.

9. Nonjurisdictional Facilities. AGD endorses this amendment as a reasonable and necessary restraint on the Commission's jurisdictional reach. Facilities for the local distribution of natural gas are often associated with NGA jurisdictional projects. Those local facilities are specifically exempted from NGA regulation pursuant to § 1(b) of the Act. Moreover, many State and local laws apply to distribution facilities, and there is accordingly simply no need for additional review by FERC as part of its NEPA responsibilities over jurisdictional projects or otherwise.

THE ADMINISTRATION'S
NATIONAL ENERGY STRATEGY (NES)

The details of the Administration's NES have only recently been disclosed. Many of the concepts contained therein are similar to those in S. 341. To the extent this is so, AGD's comments herein on S. 341 and Senator Bingaman's amendments are equally pertinent. AGD is presently reviewing the Administration's proposed bill and will provide the Committee additional comments on it as appropriate at a later time.

AGD has reviewed one of the central features of the Administration's proposal -- the abolition of FERC and the transfer of its functions to a DOE office. AGD opposes this feature of the NES. As detailed in these comments, AGD agrees that many aspects of the federal natural gas regulatory process can and should be streamlined so that the market demand for gas can be satisfied in a timely way, but the Administration's proposal to abolish FERC implies that federal regulation is no longer needed in the natural gas industry. The fact is that most interstate gas pipelines have monopoly-like market power in their service relationships with local utilities. As long as this condition prevails, AGD's position is that some federal regulation of pipelines is essential to protect local utilities and the nation's gas consuming public. AGD is also convinced that the retention of FERC will impart a desirable measure of continuity and stability to the natural gas industry, an industry which expects to expand its share of the nation's overall energy market in the near future.

CONCLUSION

AGD appreciates the opportunity to comment on S. 341 and Senator Bingaman's amendments. We are fully prepared to assist this Committee in the development of a more efficient natural gas regulatory structure that will further enhance the gas industry's ability to obtain for society the maximum beneficial use of natural gas.

AGD

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Supplemental Prepared Statement Of

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Submitted to the

UNITED STATES SENATE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

On S. 570 --

THE NATIONAL ENERGY STRATEGY ACT

March 25, 1991

On March 14, 1991, AGD submitted a prepared statement for the Committee's hearing record on Title X of S. 341, the "National Energy Security Act of 1991," and certain amendments to that bill offered by Senator Bingaman. This supplemental statement provides AGD's views on the natural gas title of S. 570, the Administration's "National Energy Strategy Act" (NES), and responds to certain issues raised at the March 7, 1991 hearing on S. 341.

As an introductory matter, it should be noted that the natural gas regulatory reform title of S. 570, the NES, goes well beyond S. 341. Rather than streamline and enhance the existing Natural Gas Act (NGA) regulatory structure, S. 570 would authorize sweeping and fundamental revisions to that structure which would alter dramatically the operation of an essential component of the natural gas industry -- interstate pipelines. AGD agrees that many aspects of the present federal regulatory structure should be streamlined and fine-tuned for the benefit of the gas industry and society at large. AGD does not, however, agree with the approach taken in S. 570 which would, as a practical matter, "re-invent the wheel" and saddle industry with a wholly unproven structure at a time when some reasonable modicum of certainty and stability in regulation is critical to achieving the market promise of natural gas.

S. 570 seems to be based upon a set of theoretical premises to the effect that the interstate pipeline industry is "competitive," that regulation of these natural monopolies is no longer in the public interest and that "market forces" can therefore elicit efficiencies which are lost by government regulation. There is certainly _some_ truth to these premises, but hardly enough to go as far as S. 570 would go toward interstate pipeline decontrol. At this point in time, the inherent market power of interstate pipelines simply cannot reasonably be ignored or dismissed to the extent done in S. 570.

It is no answer to say that much of S. 570 merely confers "options" on pipelines. The fact is that "options" such as those set forth in S. 570 will, through a combination of interstate pipeline market power, both monopoly and monopsony, and strong market demands at the city-gates and production fields, accentuate the unequal bargaining positions of industry participants and permit pipelines to extract above free market concessions from all others in the industry and, ultimately, from consumers as well. Further, in a competitive market, these "options" will more likely than not become the standard order of business and thereby replace entirely the NGA regulatory structure. The necessity for this outcome is questionable, and the appropriateness of it is similarly dubious given the dramatic changes that have already occurred in the gas industry and the fact that many elements of S. 570 could be accomplished by the Federal Energy Regulatory Commission (FERC or Commission) under present law _and_ in a manner which would allow full and considered treatment of the views and concerns of all affected parties.

COMMENT ON

TITLE II OF S. 570

Section 201 -- Interconnection Authority. AGD generally opposes further expansion of the Commission's authority to order interstate pipeline interconnections either "downstream" at delivery points or "upstream" at receipt points. NGA § 7(a) has, of course, provided authority for the Commission to order downstream interconnections for many years. This power, though used sparingly, has elicited a body of Commission precedent and case law that has defined the parameters of FERC action in such cases. Industry is generally comfortable with these procedures, but their expansion to upstream interconnections raises new issues related to potential service impairment to existing customers which are not adequately accounted for by the proposed revisions to § 7(a). Issues relating to existing capacity entitlements, transportation obligations once interconnected, and cost (beyond the physical facilities) allocation as to administration (dispatching, metering, balancing, etc.) of the interconnection are left unresolved by the proposal.

The protections set forth in proposed § 7(a)(3) are essentially a restatement of the conditions found in the "provided" clause of the present § 7(a). There is, however, a significant difference between the present § 7(a) and the proposed revision. The proposed revision includes the new § 7(k) "nonjurisdictional option" facilities, and those facilities may be for the transportation or sale of natural gas, whereas present § 7(a) facilities are for the sale of gas. This distinction is not without a difference because the present § 7(a), with its substantive safeguards as to impairment of service, and case law thereunder, relates to sales service, not transportation service. Thus, there is not an established body of law with respect to transportation only interconnections, and the issues in such circumstances can reasonably be expected to be quite different from those present as to sales interconnections.

As to proposed new § 7(a)(2), it appears that the language is crafted sufficiently precisely to exclude downstream interconnections for "bypass" purposes. It is difficult to imagine bypass circumstances where an interconnection would be sought with a natural gas pipeline "to receive" gas "from the petitioner's facilities." The issue of bypass is, however, important enough that this interpretation and the Committee's intent that the section not be applied to accomplish downstream bypass should be emphasized in the legislative history of § 7(a)(2) if it is adopted.

Section 202 -- NEPA Compliance. While the intent of this section is useful, similar language in S. 341 and Senator Bingaman's amendments accomplishes this result in a manner which is more direct, more flexible and fairer. As proposed in § 202, the authority of the Commission to charge an applicant for environmental documentation costs is wholly unrestrained and could lead to excessive and unreasonable charges.

Section 203 -- NGPA § 311 Revisions. This section is similar to the § 311 revisions proposed in S. 341. AGD is strongly opposed to these revisions for the impairment of service and bypass reasons set forth in its March 14 prepared statement. The revisions proposed in S. 570 are, however, even more objectionable than those in S. 341 because the language of S. 570 would explicitly preempt and preclude State regulation of § 311 facilities even in cases of bypass where State and local interests are at their zenith.

AGD strongly recommends that in cases of bypass of a local distribution company (LDC) either State and local regulation of the § 311 service be specifically authorized so that LDCs and pipelines can fairly compete for such service, or an LDC's willingness to provide service pursuant to State or local regulation be specified as a bar to § 311 service by a pipeline. In any event, the State preemption set forth in proposed § 311 is highly inappropriate and unacceptable.

Section 204 -- Optional Certificate Procedures. This section contains amendments to NGA §§ 4 and 7 which essentially provide that rates and charges for transportation and sales service, as well as the terms and conditions of those services, be deregulated, subject only to proscriptions against allocating costs of such services to traditional "jurisdictional" services, proscriptions against participating in proceedings involving competing facilities, and limited "NGA § 5-like" procedures which in fact approximate mandatory common carriage. Notably, this option would be available for any present, as well as new, pipeline services and facilities.

To the extent rates, abandonment, impairment of service and bypass issues are implicated here, AGD references its prior prepared statement as well as the foregoing comments herein. The issues raised in this section are in the truest sense fundamental to the operation of the interstate gas industry and its ability to continue to provide adequate and reliable service to consumers. With all due respect to the Administration's effort here, AGD firmly believes that the provisions of § 204 simply go too far too fast.

By and large, the issues raised in § 204 would be better addressed by the Commission where the multitude of interests affected and consequences engendered can be carefully assessed and resolved in a less disruptive manner. It is highly improbable that Congress will be able to assess fully the technical minutiae necessary to facilitate a fair and effective transition to the kind of regulatory structure suggested by § 204.

By contrast, the optional procedure set forth in S. 341 is a less dramatic departure from present procedures, and it retains many more due process features of present law than does § 204 of S. 570. Even at that, however, it is respectfully submitted that the administrative, as opposed to legislative, process is better equipped to produce an efficacious "option" to the existing certificate process.

Section 205 -- Nonjurisdictional Option. This section first seeks to deregulate entirely the transportation or sale of natural gas at the election of the person who would otherwise be a "natural gas company" under the NGA. The only proscription here is that such person not participate in FERC proceedings to consider any competing facilities; further, § 205 (new NGA § 7(k)) facilities would be subject to the new § 7(j) "complaint" procedures. The second objective of § 205, accomplished through the addition of a new NGA § 4(g), is to remove pipeline transportation or sales rates from NGA regulation upon a Commission finding that the market served by the pipeline is competitive and that the pipeline's transportation or sales services offered in that market are not unduly discriminatory. AGD strongly opposes both of these provisions.

As to the first provision, AGD does not believe that the interstate pipeline industry is sufficiently competitive to warrant providing to it the right to "opt-out" of NGA regulation, even with the NGA § 5-like provisions of proposed new § 7(j) which would apply to such a pipeline. The wholesale abandonment of a regulatory structure, not to mention the obvious potential loss of service, upon which tens of millions of consumers have come to rely is simply unrealistic and unacceptable. There is no evidence that such an "option" is necessary or desirable. The present NGA regulatory structure is hardly perfect, but it also is not so badly broken as to merit its outright repeal by direction or election.

The second provision of § 205, authorizing deregulation of pipeline transportation or sales rates by FERC, is equally unwise. As to the transportation function, there are very few instances where "workable competition" for pipeline capacity exists at the city-gate. Indeed, even where several pipelines serve a particular LDC, it is unusual for there to be redundant capacity, and, if there were significant redundant capacity, it would represent economic waste. Further, § 205 provides that the pertinent transportation would not be "subject to the jurisdiction of the Commission under the [NGA]" once the competitive/not unduly discriminatory findings had been made. There is, thus, no provision to "resume" NGA jurisdiction if and when circumstances arise where the now deregulated pipeline is subsequently in a position to extract monopoly concessions. Once again, the interstate pipeline industry is simply not sufficiently competitive to allow market forces to supplant regulation in all respects. What is needed is creative regulation, not no regulation.

As to the deregulation of pipeline sales rates, it should be noted that this result has already been obtained at FERC on a few pipeline systems through negotiated settlements premised upon comparability of service as between sales service and the transportation embedded in sales service. These are very complicated arrangements with numerous checks and balances to assure comparability and, thus, competitive alternatives to pipeline customers. Moreover, these arrangements today remain subject to the NGA as a further check on any subsequent, unjust or unreasonable developments. The statutory authorization for deregulation of pipeline sales rates as put forth in proposed new § 4(g) is accordingly unnecessary. New § 4(g) is also patently overbroad because, once initiated, it negates any future NGA regulation even if obviously needed. The section should not be adopted.

STRUCTURAL REFORM OF THE FEDERAL ENERGY REGULATORY COMMISSION

S. 570 proposes to abolish the Commission and replace it with a single administrator within DOE. As mentioned in AGD's March 14 prepared statement, AGD opposes this proposal.

The Commission exercises regulatory powers with far-reaching implications for virtually all sectors of society. To put these powers in one person would sacrifice the inherent equitable balancing of views and opinion which characterizes a more collegial body and which tends to elicit a more efficient decision-making process by accommodating a wide range of interests. Though not necessarily dispositive, it is notable that State public utility commissions are uniformly structured as multi-member bodies.

It should also be recognized that the administrator approach will likely "politicize" decision-making more than it is now, and, because of the large workload, necessarily increase the power of unappointed staff personnel. With all of the "sea change" developments that have been visited upon the gas industry through federal regulation over the past decade or so, it would seem advisable at this stage to foster predictability in the process. Restructuring FERC from the ground up would necessarily create uncertainty and instability at a time when just the opposite is the wiser course.

CONCLUSION

The Administration's proposal, S. 570, contributes usefully to the debate on federal natural gas regulatory reform because it implicitly questions many of the most basic assumptions underlying the status quo. Sound public policy development should include such assessments from time to time, and the Administration is to be commended for stimulating that analysis.

On the merits, AGD submits that a re-examination of the public policy foundations of the Natural Gas Act will by and large elicit a reaffirmation of those underlying principles. There is certainly a need to streamline and enhance many aspects of the natural gas regulatory process, and fundamental systemic changes are also necessary in some areas. This does not mean, however, that the core reasons for regulation have disappeared. Neither regulation nor free markets are always perfect; each can be improved and each can often benefit from application of the best of both to each other.

One key to a successful natural gas component of a national energy strategy is to find that elusive but efficient point of balance between interposing regulation when markets are insufficiently competitive and relying on free market forces when markets are workably competitive. With a more streamlined federal regulatory process which encourages and rewards negotiation and settlement rather than litigation and contentiousness, AGD submits that the FERC and the gas industry will be better able in the future to maximize the benefits of regulation and free market forces. Thus, AGD concludes that it is better to enhance the present process rather than dismantle and discard it.

AGD appreciates this opportunity to comment on S. 570 and looks forward to working with the Committee as it develops a more efficient federal natural gas regulatory process.

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Prepared Statement of

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Submitted to the

UNITED STATES SENATE

COMMITTEE ON ENERGY AND NATURAL RESOURCES

on S. 742 --

NATIONAL ENERGY EFFICIENCY AND DEVELOPMENT ACT OF 1991

April 15, 1991

On March 14, 1991, AGD submitted a prepared statement for the Committee's hearing record on Title X of S. 341, the "National Energy Security Act of 1991," and certain amendments to that bill offered by Senator Bingaman. On March 25, 1991, AGD submitted a supplemental prepared statement providing AGD's views on the natural gas title of S. 570, the Administration's "National Energy Strategy Act" (NES), and responding to certain issues raised at the March 7, 1991 hearing on S. 341. AGD is pleased now to have the opportunity to submit this further supplemental statement on the natural gas regulatory provisions of Senator Wirth's bill, S. 742, "the National Energy Efficiency and Development Act of 1991."

As AGD noted in its earlier statements, it enthusiastically supports the Committee's attention to the need for reform and streamlining of the federal natural gas regulatory structure that has been in place since 1938. AGD supports most of the reforms proposed in S. 341 and, to a lesser extent, some of the proposals embodied in S. 570. Senator Wirth's bill, S. 742, adds significantly to those bills in the areas of research and development, energy efficiency, renewable energy, and alternative transportation fuels. AGD particularly commends its emphasis on the development of natural gas as a fuel for motor vehicles and other transportation vehicles.

AGD respectfully submits, however, that certain of the natural gas regulatory proposals in S. 742 would unfortunately impair, rather than advance, the development of a healthy, enlarged market in this efficient and clean-burning fuel.

COMMENT ON TITLE IV OF S. 742

Section 406 -- Federal Regulation of VNG

AGD generally supports provisions of this type designed to remove federal regulatory impediments to the development of a strong market in vehicular natural gas ("VNG"). AGD particularly supports the formulation in Section 406(d), which assures that engaging in VNG transactions will not subject local gas distribution companies to federal regulation under the Natural Gas Act ("NGA").

COMMENTS ON TITLE VII OF S. 742

Section 703 -- Definitions

The definition of "just and reasonable" in Section 703(d) would render inapplicable all Commission and court precedent defining this term. This attempt is, in AGD's view, unwieldy and unworkable. The body of law defining the Natural Gas Act term "just and reasonable" is truly enormous. The suggestion that there would now be two just and reasonable standards -- one defined by those precedents and one having an entirely different meaning limited to this Act -- seems guaranteed to create confusion and regulatory uncertainty.

Section 706 -- Incentive Ratemaking Options

This section proposes some rather radical amendments to Section 4 of the Natural Gas Act. First, it would codify the rate design goals embodied in the Commission's rate design policy statement (Interstate Natural Gas Pipeline Rate Design, 47 FERC ¶ 61,295, order on reh'g, 48 FERC ¶ 61,122 (1989)). While those goals are in large part laudable, it would be unwise to codify them in legislation. The Commission's study of rate design objectives has been going on for decades, and it is not over. The Commission should have the freedom, within the statutory constraints of existing NGA § 4, to develop and modify these objectives guided by its experience with the rapidly changing markets of the '90s. No one formulation of them should be codified.

Second, this section would provide that pipeline rates are deemed just and reasonable if they meet any one of three tests. The first test appears to be a paraphrase of the traditional "just and reasonable" standard under NGA § 4. But in the effort to select one phrase from all the case law explicating that standard it is necessarily an oversimplification. The second test is compliance with a FERC-prescribed incentive formula. Codification of this test would appear to be unnecessary, because FERC already has the power to develop incentive formulae for rates within the bounds of the traditional just and reasonable standard. The third test is establishment of the rate within a FERC-prescribed zone of reasonableness. The upper limit of such a zone is defined as the rate yielded by valuing all the pipeline's investment at current market value (as opposed to depreciated original cost, as is now the case). The resultant rate would be significantly higher than current pipeline rates or rates under the preceding two tests. Since the pipeline would be free to charge any rate within the zone of reasonableness, and to utilize its choice of the three tests deemed just and reasonable, it is likely that pipeline rates would swiftly gravitate towards this upper limit. Such inflated pipeline rates would be extremely detrimental to the development of the natural gas market and could make it impossible for natural gas to compete with alternative fuels that are less clean, less efficient, and less domestically plentiful.

Section 707 -- Rehearing Time Limits

AGD applauds this provision as ameliorating one of the worst causes of regulatory delay in the FERC process. A similar amendment should be made to the Natural Gas Policy Act ("NGPA").

Section 708 -- Filing of Joint Rates

AGD is not aware of any record or fact pattern warranting the exemption from the antitrust laws proposed in this provision. An exemption should not be crafted to solve a hypothetical problem.

Section 709 -- Fair Return on Investment

To the extent this provision codifies the "used and useful" standard for inclusion of pipeline facilities in a pipeline's rates, it would appear to add nothing to existing law. To the extent it makes new law by virtue of what it omits (as, for example, the requirement that such investment also be prudent), it is troubling. To the extent it oversimplifies a well-developed body of precedent under the Natural Gas Act, it is counterproductive; it could be read, for example, to require the allocation of all the pipeline's facilities to the development of rates for each of its various unbundled services, instead of allocation of only those facilities that are used and useful for that particular service.

Section 710 -- Competitive Sales Services

This provision would completely deregulate pipeline sales rates if the Commission finds that the sales market is workably competitive. The definition of "workable competition" in Section 703(h) is circular, so that as a practical matter FERC would have unfettered discretion to give meaning to that standard and hence to deregulate pipeline sales rates. This would be, in AGD's view, a completely unwarranted and unnecessary abdication of Congress' responsibility. Pipeline service remains today a monopoly resource. With true comparability as between sales and transportation service, the Commission has shown in several recent instances that sales rate regulation can be reduced. These are, however, very complicated and pipeline-specific decisions which should not be made by Congress in the absence of detailed analysis and findings which are better left to the administrative process.

Section 711 -- Competitive Services

This provision goes beyond the non-certificate options proposed in other bills by creating several categories of new service that are completely and automatically exempt from certification requirements, without the concomitant proviso that the pipeline is at risk for the costs of the facilities. These categories would include (1) services provided by facilities constructed under NGPA § 311, and (2) services that do not require any major new construction. A third category -- services that are alternative to existing rate-regulated services -- are completely exempt from *rate* regulation. Thus certain services could be exempt from both certificate and rate regulation. Yet the costs of all three types of services, or the losses incurred by the pipeline as a result of offering these services, could be incorporated, in later rate cases, in the pipeline's regulated rates for other services. Such one-sided generosity to pipelines cannot be reconciled with the consumer protection goals of the Natural Gas Act.

Section 712 -- Pipeline Abandonments

AGD opposes this provision. It would remove the abandonment protections that now exist under NGA § 7(b) to protect a sales customer from a pipeline's termination of jurisdictional sales service at the expiration of the underlying sales contract. The pipeline would be free to terminate sales service to a customer, such as a local distribution company, at the end of the sales contract even though the present and future public convenience and necessity require its continuation.

This kind of unlimited abandonment jeopardizes the LDC's supply security and ability to meet its own service obligations. It also gives the pipeline virtually unlimited bargaining power to extract favorable terms and conditions from a customer nearing the end of its sales contract who cannot afford to risk termination of the service. Finally, such unlimited abandonment could have a chilling effect on the role historically played by sales customers, in the Natural Gas Act scheme, of monitoring, scrutinizing, and protesting certain pipeline rates or expenditures; customers may be loathe to attract attention to themselves or alienate the pipeline if the pipeline can respond by cutting them off at the end of their contract.

Section 713 -- Producer Demand Charges

AGD opposes codification of the rate treatment of producer demand charges. The appropriate rate treatment is a pipeline-specific matter and is closely tied to each pipeline's other rate structure -- in particular, to whether it has a gas inventory charge (GIC) and, if so, what kind of GIC. The purpose of a GIC is to compensate the pipeline for the costs of maintaining an inventory of sales gas. Producer demand charges are one kind of such cost. The appropriateness of as-billed recovery of producer demand charges also depends on whether the pipeline has given its customers a reasonable opportunity to first adjust their firm purchase entitlements and/or convert them to firm transportation.

Clearly these are important distinctions that fall within the expertise of FERC to evaluate; it would be a mistake to brush them aside in generic legislation.

Section 714 -- Natural Gas Imports

This provision appears to be unnecessary, in that FERC already has the power to act to impose conditions on imports where they are truly needed. It would also appear to be unwise to inhibit imports by statute, even where no such condition is appropriate, in the present climate of need and demand for expanding supplies of natural gas and in light of the U.S.-Canadian Free Trade Agreement.

Section 716 -- Section 311

Like Section 711, this provision would broaden the availability of an unregulated option for pipeline services and facilities, while giving the pipeline the opportunity to choose, for any given service, a regulated option, where it works to the pipeline's advantage. The only criteria for use of the unregulated option are that the pipeline be "open access" and agree to do "open access" transportation through the proposed facilities. The option would be deregulated both as to certificate requirements and rate regulation, because it provides that the NGA simply would not apply to the covered facilities or their operation. AGD opposes such broad-based pipeline deregulation, which would allow existing customers' rights to service to be adversely affected without remedy.

CONCLUSION

S. 742 is a comprehensive bill that brings together many useful proposals on energy efficiency and the development of programs to enhance the use of natural gas in this country. AGD particularly commends its proposals for removing regulatory barriers to the development of a market for vehicular natural gas.

The natural gas regulatory proposals in the bill are, however, by and large inconsistent with the consumer protection goals of the Natural Gas Act and the continued need for procedural and substantive protections for customers against the monopoly power of pipelines.

AGD appreciates this opportunity to comment on S. 742 and looks forward to working with the Committee as it develops a more efficient federal natural gas regulatory process.

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April 16, 1991

The Honorable Timothy E. Wirth
Chairman, Subcommittee on Energy
  Regulation and Conservation
Committee on Energy
  and Natural Resources
United States Senate
364 Dirksen Senate Office Building
Washington, D.C. 20510-6150

Dear Senator Wirth:

The Petrochemical Energy Group (PEG) appreciates very much the opportunity to comment on Title VII, "Measures to Promote The Use of Natural Gas", in S. 741, the "National Energy Efficiency and Development Act of 1991." We will confine our comments to the Sections on New Uses for Natural Gas and Regulatory Issues, Wellhead Prices, Regulation of Natural Gas Imports, and Accelerated Pipeline Construction.

PEG, as you know, was a sponsor of the testimony of F. Joseph Graham of Union Carbide Corporation presented to the Committee on Energy and Natural Resources on March 7, 1991. Our views on the overall goals recommended to the Congress are fully stated there, including the goal of restricting the monopoly and monopsony power of interstate natural gas pipelines. Some of the proposed sections in S. 741 would, in our view, enhance the ability of interstate natural gas pipelines to engage in predatory and anti-competitive behavior, even though the intent in S. 741 is clearly to the contrary. Our reasons for reaching this conclusion will be given in connection with the relevant sections discussed below and in Appendix A, where we review the Sections in more detail.

In summary, S. 741 would:

(1) Raise the rates that the interstate pipelines can charge above the level of just-and-reasonable rates. Section 7006.

(2) Permit pipelines to collude together outside either the Natural Gas Act or the antitrust laws of the United States to shift costs from one pipeline to another, at the expense of competition and captive consumers, by means of joint rates. Even affiliated pipelines would be thus immunized. Section 7008.

(3) Assuming that only gas costs and not other costs are included in Section 7009, the pipeline's merchant function would be deregulated. Thus, the pipeline could sell the commodity of gas at whatever the traffic would bear. There is a very necessary predicate required: that the pipeline not have monopoly or monopsony power, that comparable third party transportation for competitors be provided, and that no costs can be shifted to captive customers, whose rates will continue to be regulated. However, as a result of (1), the captive customers will still be paying higher than just-and-reasonable rates. For those sales of the commodity of gas that are deregulated, the rates will be secret, rasing concerns about undue discrimination.

(4) Permit the pipeline to offer new services that duplicate existing service without any oversight by the Commission. The "new" duplicate service can be offered on a discriminatory basis to affiliates or to other favored customers at whatever rates, terms, and conditions that the pipeline pleases. The Commission is only allowed a limited, after the fact, review, but only with respect to the regulated service. This restores the monopoly power of the interstate pipelines. Section 7011.

(5) Permit the pipeline to charge all sales customers all or part of their payments for gas supply, whether the sales customers choose to buy gas from the pipeline or not. This would stifle competition for sales of gas and render any remaining "open access" transportation meaningless. Section 7013.

(6) Only allow presently certificated interstate pipelines to build Section 311 transportation facilities and continue to bar use of the facilities for transportation to producers and end users, thus perpetuating and increasing the discrimination presently existing in the interstate market. Section 7016.

We respectfully urge that S. 741 not be adopted with respect to the Sections summarized above and in the appendix. The result would be higher rates for a degraded service for those who are dependent on the public utilities who transport and sell gas in interstate commerce under federal license, with restoration of the pipeline monopoly and monopsony power.

Again, we appreciate the opportunity to comment on S. 741. If we may be of further assistance, please do not hesitate to contact us.

Very truly yours,

A. Richey Dodds
Chairman

cc: The Members of the Committee
on Energy and Natural Resources

Appendix A to Letter of April 17, 1991, to Senator Wirth
Analysis of Selected Sections of S. 741

Section 7004, pertaining to research and demonstration of various techniques for using gas and coal in combination, appears to be limited in scope to electrical utility and industrial boilers. We respectfully urge you to consider that there are other potentials, including the petrochemical usages for feedstocks, process fuels, plant protection, and other non-boiler fuel uses. There should be no restriction of R&D only to boiler fuel usage.

REGULATORY ISSUES

Section 7006(a), incentive ratemaking options, should not be adopted. This section provides for three methods for assuring that the rates charged by public utilities are just-and-reasonable, only one of which has the likelihood of achieving that goal. The first alternative appears to be a restatement of the present ratemaking method determined by the Courts to yield "just-and-reasonable" rates.

Methods two and three are new. It is not really possible to comment on the method two option, since there are no clear standards set for the Commission to follow. It thus appears to provide a blank check for the regulators to write on as they please. In our view, this is too much power to delegate, if indeed such power is delegatable.

Method three appears to adopt the much litigated and still highly uncertain model for setting rates on oil pipelines, insofar as the maximum rate is concerned. It seems most clear that allowing a gas pipeline to "write up" its assets above that now allowed by the FERC would clearly result in rates that are higher than the current just-and-reasonable rates. Yet the floor set by this provision again appears to be a restatement of the current ceiling rates under a just-and-reasonable standard. It thus appears that this section would drive the rates of interstate natural gas pipelines above a just-and-reasonable level, to the detriment of both producers and consumers of natural gas.

Section 7006(b), amending Section 5 of the NGA, effectively removes Commission jurisdiction to set "just-and-reasonable" rates for interstate natural gas pipeline companies. By striking the jurisdiction of the Commission to set rates at the "lowest reasonable rates", this provision would eliminate the Commission's ability to set just-and-reasonable rates either in connection with new rate case filings initiated by a pipeline under the NGA or in a Section 5 proceeding to review existing rates. It thus undercuts even the reaffirmation of the power to set just-and-reasonable rates contained in Section 7006(a)(1).

With the added language, the FERC would have to set rates at a higher than just-and-reasonable level, thus effectively defeating the interests of consumers. This provision should not be adopted.

Section 7007, dealing with time limits on rehearing, should be adopted in order to avoid denial of due process and to prevent arbitrary administrative action.

Section 7008, dealing with the filing of joint rates, should not be adopted. Many pipelines today are parts of giant conglomerates, where several pipelines are affiliated, along with marketing companies and affiliated producers. Allowing joint rates is an open invitation for the conglomerates to control market share and access by shifting the costs of one affiliated pipeline to another pipeline, thus creating either barriers to competition or subsidies. In addition, any "negotiation" between affiliates can hardly be considered arms length or market sensitive, and even the "negotiations" between two regulated public utilities are not likely to give much concern for the interests of producers, consumers, or competitors. Rates should be individually set by each pipeline. The true effect of this provision is amply demonstrated by the relief from any antitrust liability for operation under joint rate agreements. The pipelines should remain as fully subject to the antitrust laws as they presently are.

Section 7009, fair return on investment, does not appear in plain meaning to change the status quo to any material degree and thus its adoption is questioned.

Section 7010, while technically an amendment to the NGPA, actually amends the Natural Gas Act in a way different from Section 7006. It appears that the overall intent of this provision is to deregulate the sales for resale in interstate commerce by interstate pipeline companies where the pipeline does not exercise monopoly or monopsony power; and where comparable third party transportation service is provided. When these conditions are met, then two consequences flow: (a) the pipeline may make a profit or a loss without there being any effect on rates for any other services; and (b) the pipeline's rates may be held secret, since there would no longer be any requirement that rates be on file at the Commission. Three comments should be made:

First, it is not clear that the only item to be included within the "sale for resale" is the commodity of gas itself and not other components of rates, usually called "non-gas" costs, that are usually embedded in any "sale for resale" rate. In context in this portion of the NGPA, it could be inferred that only the commodity of gas itself is involved in this provision, but clarification should be made.

Second, the limitation on affect on the rates of others is very beneficial. Since this provision obviously contemplates some services being deregulated and some regulated, it would be most unfortunate if the pipeline were allowed to shift costs from the deregulated customers to the captive customers, and this provision obviously is intended to see that the regulated rates are on a stand-alone basis and will not subsidize losses or make profits possible on the deregulated business.

Third, removing the requirement that public utilities file rates for public inspection means that the public loses the opportunity to screen for unlawful discrimination or favoritism, such as for an affiliate. Unless this type of behavior is intended to be permitted, this provision should not be enacted.

Section 7011 appears to be a free standing provision that materially alters transportation under Section 311 of the NGPA without correcting the current discrimination against use of Section 311 transportation by all consumers and customers. Each subsection will be discussed in turn.

(a) dealing with certificates for providing service under Section 311, does not appear to add anything to existing law.

(b) is a radical departure from present law, allowing an interstate pipeline to offer a new service without prior review by the Commission to see that the new service is in the public interest, such as being offered on a non-discriminatory basis. By eliminating certificate jurisdiction, the Congress would prevent the Commission from conditioning new services in order to protect the public interest.

(c) adds to (b), by removing even the rate jurisdiction over new services, provided that the "new" service duplicates an existing service. The result is that favoring an affiliate or offering unreasonable terms and conditions, except as to non-competitors, would be legitimatized. This adds to the pipeline monopoly and monopsony power.

(d) as a partial offset, and an inadequate offset, the Commission is allowed to consider the effect of the deregulated duplicated services on the regulated services, but how is not provided.

Section 7012 appears to (a) allow an interstate pipeline to cut off sales to local distribution companies and to other interstate pipelines upon the expiration of contracts, regardless of whether the jurisdictional sales customer has lined up a substitute supply or not, and (b) forbid an interstate pipeline to cut off transportation service of a jurisdictional sales customer who has converted to firm transportation when the contract expires, unless the Commission permits it. So long as the pipeline does not exercise monopoly or monopsony power and so long as comparable third party transportation is a reality, these provisions are not objectionable. However, the stated conditions should be imposed by statute.

WELLHEAD PRICES

Section 7013 appears to require that the Commission allow certain payments to producers, whether affiliated with the pipeline or not, to be billed to all sales customers on a guaranteed payment basis, provided that the pipeline is found by the Commission to offer comparable third party transportation service. While the condition is appreciated and should be imposed throughout, it has no effect in this situation. If a pipeline can force all sales customers to pay all or part of the payments to producers for natural gas on a guaranteed basis, whether they choose to buy gas from the pipeline or not, having access to transportation service is virtually meaningless. Not only will the sales customers have to pay the pipeline for gas supply which they do not choose to buy, but a competitor cannot overcome the advantage that the pipeline has in its merchant function. To illustrate, assume that the fair market price for gas at the wellhead is $2.00. In theory, either the pipeline or a competitor should be able to charge that amount. But the pipeline can force all sales customers to pay, say, $1.50 in a fixed monthly charge, whether they buy any gas from the pipeline or not. The pipeline can then offer to sell units of gas at $.50 each without being out any unrecovered costs. A competitor must then offer units of gas at $.50 to compete, losing $1.50 each, an impossible barrier. The pipeline monopoly and monopsony will thus be restored.

REGULATION OF NATURAL GAS IMPORTS

Section 7014 apparently requires the Commission to establish a level playing field in rate design between pipelines offering imported gas and domestic pipelines.

ACCELERATED PIPELINE CONSTRUCTION

Section 7016 amends Section 311 of the NGPA by codifying that construction of facilities are authorized, but limited to persons that are natural gas companies already holding certificates for the transportation of gas in interstate commerce. The reason for this latter limitation is not clear. If Section 311 construction is to be authorized, all classes of persons should be allowed to build in order to enhance competition.

Section 7016 does not correct for the "on behalf of" problem that operates to exclude certain classes of customers from utilizing Section 311 transportation, including end users. This correction should be made.

This section does mandate open access, a beneficial requirement in any statute on this subject.

Section 70016's new (d)(3) apparently codifies the present practice of pipelines that construct under Section 311 and then seek a certificate under Section 7 of the NGA.

Section 7017 creates a rebuttable presumption pertaining to no significant impact on the environment, under stated circumstances.

Section 7018 makes the FERC the primary decision maker with respect to environmental matters.

Section 7019 apparently codifies the current Commission practice of phasing pipeline construction cases into regulatory and environmental sets.

Section 7020 further refines the environmental review process by giving greater latitude to pipelines in the preparation and submittal of environmental impact assessments.

American Paper Institute, Inc.
1250 Connecticut Ave., N.W., Suite 210, Washington, DC 20036
(202) 463-2420

1991

March 19, 1991

The Honorable J. Bennett Johnston
Chairman
Senate Committee on Energy and Natural Resources
Washington, D.C. 20510

Dear Mr. Chairman:

The American Paper Institute is the national trade association of companies that manufacture pulp, paper and paperboard in the United States. As an energy intensive industry, we have views on a number of issued included in S. 341.

Enclosed are two statements of the American Paper Institute on S. 341 which we hope you will include in the appropriate hearing record. Specifically, they are the hearings of:

I. March 7 on Natural Gas Use

II. March 14 on Reform of the Public Utility Holding Company Act

This letter of transmittal need not appear in the record. Thank you very much.

Sincerely,

Jeremy M. Metz
Director
Energy, Material & Technology

Marc D. Yacker

Marc D. Yacker
Director
Congressional Relations

JMM/MDY/cs

Paper Industry USA
300 Years of Progress
1690-1990

STATEMENT OF THE AMERICAN PAPER INSTITUTE
TO THE SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
ON S. 341
THE NATIONAL ENERGY SECURITY ACT

Title X
Natural Gas

March 7, 1991

COMMENTS OF THE AMERICAN PAPER INSTITUTE, INC. ON NATURAL GAS LEGISLATION

The following reflects the views of the American Paper Institute, Inc. ("API") on the natural gas provisions of the proposed National Energy Security Act of 1991 (S. 341, Title X) and the Bingaman Amendment thereto. In addition, where appropriate, we have cited certain provisions of the Administration's proposed Natural Energy Strategy Act of 1991.

API is the trade association of the pulp, paper and paperboard manufacturers in the United States. Its members produce over 90 percent of this Nation's pulp, paper and paperboard. API's members compete with foreign manufacturers of paper products for sales both here and abroad.

Paper products manufacturing is a highly energy intensive process. API's members are major industrial users of natural gas. For example, in 1989 they consumed approximately 342 Bcf of natural gas. That level of consumption makes the paper industry the sixth largest consumer of natural gas among manufacturing industries. The delivered price of natural gas, including gas transportation charges, is a significant cost component in the pulp, paper and paperboard manufacturing process and can directly affect the paper industry's ability to compete in the marketplace with foreign suppliers.

In these comments, API focuses on the following limited features of both bills that are of particular concern to the paper industry:

1. Pipeline Construction Initiatives
2. Amendment of Section 311 of the Natural Gas Policy Act of 1978 ("NGPA")
3. Rate Deregulation
4. The Federal Energy Regulatory Commission
5. Gas Import/Export Deregulation

Pipeline Construction Initiatives

S. 341 would allow interstate natural gas pipeline companies to build facilities to provide transportation service without first obtaining a certificate of public convenience and necessity from the Federal Energy Regulatory Commission ("FERC") under Section 7 of the Natural Gas Act ("NGA") and would provide that, once the pipeline commences services, the FERC would be required to issue the Section 7 certificate. The Bingaman Amendment filed to amend S. 341 would streamline the traditional Section 7 certificate procedure, directing FERC to grant a certificate in uncontested cases, eliminating the certificate requirement for replacement of obsolete or deteriorating pipeline facilities, and establishing expedited procedures for "priority projects" designated by the FERC Chairman. The Administration's proposal would provide two alternatives to the traditional Section 7 certificate procedure for the construction and operation of pipeline facilities.

In general, the paper industry supports legislation which would facilitate the construction of new gas pipeline facilities. The paper industry finds laudable the efforts to expedite pipeline construction embodied in S. 341, the Bingaman Amendment and the Administration proposal. The paper industry does have some concern, however, that the Administration's proposal may go too far.

Under the non-jurisdictional option, the Administration bill would permit any person to "acquire, or operate" pipeline facilities without FERC authorization. By its terms, the bill authorizes the conversion of existing, certificated pipelines to non-jurisdictional ones. The paper industry cannot support such a provision. In essence, the Administration bill would permit a pipeline company (a) to operate parts or all of its existing system as non-jurisdictional facilities, or (b) to create affiliates to acquire parts of the existing pipeline and operate them as non-jurisdictional facilities. This provision could allow existing essential pipeline facilities to become non-jurisdictional facilities, thereby creating the potential for significantly increased rates for, or indeed monopoly rents from, all customers using such facilities.

Moreover, under the Administration's provision, the potential for cross-subsidization among the pipeline's customers and abusive affiliate transactions would be substantial. For example, the Administration bill would not expressly prohibit a pipeline from subsidizing its customers utilizing the non-jurisdictional facilities with the revenues collected from its customers utilizing its jurisdictional facilities. Thus, under the Administration bill, a pipeline could spin-off jurisdictional facilities to affiliates for operation as non-jurisdictional facilities at unregulated rates. The affiliate could then charge the pipeline rates for service on the non-jurisdictional facilities that are higher than cost of service levels, thereby reducing the rates for the affiliates' other customers or reaping windfall profits for the affiliate shareholders at the expense of the customers of the jurisdictional pipeline. The non-jurisdictional option should therefore be limited solely to new facilities, and non-jurisdictional pipelines should not be permitted to provide service to jurisdictional pipelines without prudence oversight of the jurisdictional pipelines' purchases.

The Administration bill would also grant FERC authority to require pipelines to interconnect with other facilities. Although the paper industry generally supports that provision of the Administration proposal, it would favor some changes. Specifically, the paper industry would urge the deletion of FERC authority to order non-jurisdictional pipelines to interconnect with other facilities. Under the Administration proposal, if an API member were to build a new pipeline pursuant to the non-jurisdictional option to serve its own paper plant, FERC could order that member to interconnect and serve an adjacent LDC or township. That interconnection authority would be inconsistent with the non-jurisdictional option and, by imposing the threat of regulation, would only deter pipeline construction, in direct contravention of the purposes of the Administration bill.

With the exception of facilities constructed under the non-jurisdictional option, the paper industry would favor expanding FERC authority to order interconnections of jurisdictional pipelines to receive and transport gas to include the authority to order interconnections for the _delivery_ of gas to _any_ person. The true monopoly power of interstate pipelines lies in transmission. FERC authority to order interconnections for the delivery of gas would reduce pipeline market power and further open the gas market to competition.

Finally, the paper industry is concerned about who would bear the costs of new pipeline facilities and believes that, at a minimum, customers of existing regulated facilities should not bear the costs of any new unregulated facilities unless they use those facilities. The Administration bill only partially addresses the issue. It explicitly prohibits the allocation of costs of new facilities authorized under its optional certificate program to existing ratepayers. However, the Administration bill should be amended to prohibit expressly the assessment of costs of new facilities authorized under the non-jurisdictional option to existing ratepayers as well.

Although S. 341 allows the costs of new facilities to be rolled in with the cost of existing facilities after ten years, the new facilities whose costs would be rolled in would be subject to FERC rate regulation. Thus, the paper industry can support S. 341 on this issue. However, S. 341 should be clarified to provide that at the end of the ten-year period, such new facilities would not be allocated to existing ratepayers at greater than the new facilities' then-depreciated costs.

Amendment Of NGPA Section 311

"On Behalf Of" Requirement: The paper industry supports expanding the class of transactions permissible under NGPA Section 311. Both S. 341 and the Administration bill accomplish that by permitting transportation by an interstate pipeline "on behalf of . . . any other person." The Administration proposal would be broader than S. 341 and would authorize similar transactions by intrastate pipelines as well. The paper industry supports the more expansive provision of the Administration proposal.

S. 341 would also extend the NGA non-discriminatory rate standard to Section 311 transactions for the first time. The paper industry favors that amendment to NGPA Section 311.

Construction: Both S. 341 and the Administration bill would amend NGPA Section 311 expressly to permit construction of pipelines under that provision, albeit in different ways. S. 341 would require a FERC rule or order prior to such construction authorizations. The Administration bill would only require thirty days notice to the State regulatory authorities prior to construction. The paper industry can support either bill on Section 311 construction.

Rate Deregulation

In addition to proposing light-handed regulation of pipelines constructed or operated pursuant to the non-jurisdictional and optional certificate alternatives, the Administration bill would amend NGA Section 4 to permit FERC to deregulate a new or existing pipeline's sales and transportation rates within a specific market if FERC first finds that the market is "competitive" and the pipeline offers its services in that market on a "not unduly discriminatory basis."

API strongly opposes this provision of the Administration's bill. First, it is extremely unlikely that any pipeline could meet the burden it would have to make to demonstrate that its market is truly competitive in light of limitations on the pipeline's capacity and limitations on the transmission capacity upstream and downstream of the pipeline. At the local distribution company level natural monopolies still exist. Thus, the potential for regulatory abuse under this provision would be significant.

Second, even if a determination could be fairly made that a pipeline market is truly competitive, the determination could become obsolete very quickly due to the dynamics of the gas industry and individual transactions, not to mention the propensity of pipeline companies to merge. The paper industry believes that the regulatory process simply could not keep up with such changes, and that during the period of delay, many abusive results could occur.

Finally, the deregulation of pipeline sales and transportation rates is simply not required to meet the Administration's objective -- establishment of competitive, market clearing sales and transportation rates. The Supreme Court recently confirmed FERC's authority to set just and reasonable ceiling rates for wellhead gas sales still subject to regulation at levels above market clearing rates, thus, permitting the buyers and sellers to negotiate market clearing prices within the ceiling rates. See Mobil Oil Exploration & Producing Southeast, Inc. v. United Distribution Companies, 59 U.S.L.W. 4054 (Jan. 8, 1991). Similarly, the courts have confirmed FERC's authority to permit pipelines to discount transportation rates below just and reasonable ceiling rates. See Associated Gas Distributors v. FERC, 824 F.2d 981, 1007-1010 (D.C. Cir. 1987), cert. den., 485 U.S. 1006 (1988). FERC could apply this rate flexibility to pipeline sales rates, allowing sales discounts to market clearing levels. This authority would give the pipelines the discretion to reduce rates to meet competition, but still give natural gas buyers protection from monopoly rents above just and reasonable ceiling rates.

The paper industry favors continued Federal oversight of interstate pipeline sales and transportation rates, including pipeline capacity assignment and brokering.

The Federal Energy Regulatory Commission

The paper industry favors legislation to expedite and encourage more timely FERC decisions. Therefore, the paper industry supports the S. 341 initiatives with respect to adoption of FERC rulemaking procedures and limitations on the timing of FERC rulings on rehearing and the filings for judicial review of FERC orders.

Import/Export Deregulation

The Administration bill would amend NGA Section 3 to eliminate, with one exception, the need to obtain prior approval from FERC or DOE for gas imports or exports. Under the Administration proposal, importation of gas would be considered an NGPA "first sale." Thus, imported gas would be treated as if it were domestic wellhead gas, that is, deregulated. Gas produced domestically for exportation would be similarly treated. Moreover, the Administration bill would preclude FERC or State regulation of gas imports or exports under any other source of authority.

The paper industry supports the Administration legislation. Deregulation of natural gas importation and exportation would eliminate an extra regulatory process that has become almost meaningless and that no longer exists for most domestically produced gas. Thus, the Administration's bill would create more competition among gas from all sources. However, purchases of imported gas by interstate pipelines or local disbribution companies should remain subject to prudence review by FERC or state commissions, as the case may be, to prevent abuse.

The goal of Title X of S. 341 is "to remove the regulatory barriers to natural gas achieving its potential" in our Nation's energy marketplace. Similarly, the Administration's National Energy Strategy has as its principal aim "a more efficient, less vulnerable, and environmentally sustainable energy future." The paper industry strongly endorses those goals and, where appropriate, supports legislative initiatives that advance those goals. API appreciates your consideration of the paper industry's views in these matters.

Fuel Managers Association

FOUNDING MEMBERS

C.C. Pace Resources
CNG Energy Company
Cogeneration Partners of America
Destec Energy, Incorporated
Hadson Development Corporation
Mission Energy Company
Simpson Paper Company
Westinghouse Electric Corporation

Counsel

Chadbourne & Parke

March 21, 1991

The Honorable J. Bennett Johnston
United States Senate
Chairman, Committee on Energy and
Natural Resources
364 Dirksen Senate Office Building
Washington, DC 20510

RE: Testimony of the Fuel Managers Association on Proposed Legislation Concerning Natural Gas Regulatory Issues

Dear Senator Johnston:

Please find enclosed for the hearing record on S. 341 an original and five copies of the "Comments of the Fuel Managers Association on Natural Gas Legislation."

Your attention to this matter is appreciated.

Sincerely,

Timothy F. Sutherland
President

TFS/rj

Enclosures

4375 Fair Lakes Court, Suite 2020, Fairfax, Virginia 22033 Telephone 703 803 6369 Facsimile 703 818 9108

Fuel Managers Association

COMMENTS OF THE FUEL MANAGERS ASSOCIATION ON NATURAL GAS LEGISLATION

FOUNDING MEMBERS

C C Pace Resources

CNG Energy Company

Cogeneration Partners of America

Destec Energy, Incorporated

Hadson Development Corporation

Mission Energy Company

Simpson Paper Company

Westinghouse Electric Corporation

Counsel:

Chadbourne & Parke

These comments reflect the views of the Fuel Managers Association ("FMA") on those provisions of the proposed National Energy Security Act of 1991 (S. 341), the Bingaman Amendment thereto, and the proposed National Energy Strategy Act of 1991 (S. 570, H.R. 1301) (the "Administration's proposal") that pertain to natural gas regulatory issues.

FMA is an incorporated association representing companies that own, develop or manage non-utility cogeneration and independent electric power projects located in North America, or that act as fuel managers to such projects. The fuel of choice for many of these projects is natural gas, and the electric generation industry is the fastest growing new market for natural gas in the United States. Thus, FMA represents a growing base of new customers for the transportation services of interstate natural gas pipelines.

These comments address those features of the proposed legislation that are of particular concern to FMA, namely: (1) construction of new natural gas pipeline facilities; (2) amendment of Section 311 of the Natural Gas Policy Act of 1978 ("NGPA"); (3) rulemaking, rehearing and review procedures relating to the Federal Energy Regulatory Commission ("Commission"); and (4) natural gas import/export deregulation.

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Construction of New Natural Gas Pipeline Facilities

Due to contractual obligations and environmental limitations on the use of fuel oil, many cogenerators and independent power producers ("IPPs") require firm natural gas transportation service. Such service is generally unavailable through existing pipeline systems, however, because of capacity constraints. With few exceptions, cogenerators and IPPs must rely on the construction of new pipeline facilities for the firm natural gas transportation service they require.

Many of the legislative proposals would expedite the construction of new natural gas pipeline facilities. Each of S. 341, the Bingaman Amendment and the Administration's proposal would streamline the procedures employed by the Commission in authorizing the construction of interstate pipeline facilities through the issuance of certificates of public convenience and necessity pursuant to Section 7 of the Natural Gas Act ("NGA"). Moreover, both S. 341 and the Administration's proposal would authorize the construction of interstate natural gas pipelines without prior certificate authorization from the Commission. The FMA fully supports these measures to remove the regulatory barriers to market entry in the pipeline business and facilitate the construction of new natural gas pipeline facilities.

Amendment of Section 311 of the NGPA

Both S. 341 and the Administration's proposal would amend Section 311 of the NGPA to authorize the transportation of natural gas by interstate pipelines "on behalf of" any person, rather than on behalf of interstate pipelines and LDCs only, and to expressly authorize the construction of interstate pipeline facilities to provide such transportation service. However, while the Administration's proposal would authorize the construction of such facilities upon 30 days' notice to the affected state commission, S. 341 would require that the Commission first authorize the construction activity by rule or order. The delay inherent in requiring prior Commission approval of such construction activity by order would only create unnecessary administrative burdens for the Commission, pipelines and their customers, and would impede the efforts of producers, marketers and end-users to make arrangements for natural gas transportation service with the expedition necessary to achieve the full benefits of the current competition at the wellhead. Accordingly, although FMA would support either legislative proposal, FMA favors the less burdensome provision of the Administration's proposal.

Rulemaking, Rehearing and Review Procedures Relating to the Commission

S. 341 contains provisions that would expedite the Commission's decision-making process. These provisions are supported by FMA, whose members believe that a streamlined decision-making process would enhance the natural gas industry's ability to respond effectively to market conditions. Specifically, FMA supports provisions that would allow rulemaking proceedings to be used in contested cases involving the certification of new natural gas pipeline facilities and services; require issuance of a final order on rehearing within a defined time period; and tighten the requirements for obtaining judicial review of a Commission order.

Regarding the rulemaking provision, FMA believes that this can significantly reduce the amount of time required in obtaining a decision on contested certificate cases. Many of these cases remain before the Commission for months or even years, and just the existence of a protest can thwart the original petitioner's request. This is not necessarily adverse to the public interest; however, a streamlined decision-making process can reduce the needless waste of time and unwarranted delay.

FMA believes this would be accomplished by the Senate proposal. S. 341 incorporates the safeguards that allow public comments during the rulemaking process, but eliminates the Commission's need to hold long, trial-type hearings in contested certificate cases. These provisions should be included in legislation enacted by Congress.

FMA also supports provisions that would amend NGA Section 19 and NGPA Section 506 to require the Commission to issue a final order on rehearing within 60 days after an application for rehearing is filed. These provisions are also included in S. 341, but not in the Administration's proposal. The Commission may extend the rehearing period an additional 60 days, for a maximum of 120 days, only if "extraordinary cause" exists. FMA believes it is crucial to reduce the amount of time required to obtain a final order from the Commission, without reducing the fairness applied in the process. FMA believes the rehearing provisions support these twin objectives, and thus supports this aspect of S. 341.

S. 341 would also reduce the period for seeking judicial review from 60 days to 30 days, and petitioners would be required to state the specific grounds upon which their petition is based. FMA believes these are prudent provisions to enact, reducing the likelihood of frivolous appeals and unnecessary delay.

Natural Gas Import/Export Deregulation

FMA supports a free international gas trade, realizing that this spurs competition and tends to make additional resources available at competitive prices. Specifically, FMA supports provisions contained in the Administration's proposal that would eliminate the necessity of obtaining prior approval from the Commission or Department of Energy for gas imports or exports. FMA also agrees with the appropriateness of related proposals pertaining to the President's authority to limit or condition gas imports or exports, and to waive certain requirements or expedite related projects that are important to the national interest. Under the Administration's proposal, importation of gas would be considered an NGPA "first sale," and thus treated the same as deregulated domestic wellhead gas. Gas produced in the U.S. for exportation would be similarly treated. Furthermore, the Administration's proposal would expressly preempt the Commission or any State from using any other source of authority to regulate gas imports or exports.

FMA believes that the free-flow of natural gas through our national borders is conducive to a competitive market and will stimulate a healthy energy economy. Unnecessary restrictions will serve only to create artificial barriers, reduce supply and place upward pressure on prices. Canadian gas imports into this country, for example, have helped expand the usage of natural gas in the New England region, an area constrained by a limited gas pipeline infrastructure and pipeline capacity bottlenecks. The availability of natural gas into this region and others will serve to reduce the nation's reliance on foreign oil and the complications associated with it.

FMA appreciates the opportunity to comment on these important legislative proposals. We would be happy to answer any questions you might have.

INGAA

JOHN D. DALY
CHAIRMAN

[illegible]
1991

April 3, 1991

The Honorable J. Bennett Johnston
Chairman
Energy and Natural Resources Committee
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 14, 1991, the Associated Gas Distributors ("AGD") filed with your Committee a prepared statement on S. 341, the National Security Act of 1991. In this statement, AGD urges amending Section 4 of the Natural Gas Act ("NGA") which deals with rates for pipeline sales and transportation. AGD's proposal would replace the existing provisions of Section 4 with a straightjacket for setting pipeline rates. This, along with the Section 4 provision in your bill, S. 341, to which we have previously expressed our strong opposition, would result in substantial financial harm to the pipeline industry which has utilized Section 4 to restructure itself in response to changes in FERC regulatory policies.

The Interstate Natural Gas Association of America's ("INGAA") opposition to the AGD response is set forth in more detail in the enclosed Response in Opposition. INGAA is a national trade association whose membership includes virtually all of the major interstate natural gas transmission companies operating in the continental United States. The rates charged by these pipelines for the transportation and sale of natural gas are established by the FERC pursuant to NGA Section 4. The balance between the FERC's authority under Section 4 relative to rates proposed by the pipeline and the FERC's authority under Section 5 relative to rates that are alleged to be no longer just and reasonable is critical. The AGD proposal would destroy this balance, and for no justifiable reason.

AGD alleges interstate pipelines have "unfettered" rights to file for rate increases at any time. This overlooks the reality of competitive sales and transportation rates and services by others, as well as sales rate decreases and discounted transportation rates by pipelines in response to such market forces.

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
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AGD alleges that allowing increased rates to be collected subject to refund somehow "jeopardizes" LDC markets, but fails to acknowledge the alternate supplies and services LDCs take advantage of in today's market.

In complaining about the so-called "pancaking" of rate cases under Section 4, AGD overlooks the pressure pipelines face to resolve rate proceedings quickly and amicably in order to avoid the buildup of reserves and the fiscal uncertainties inherent with unresolved rate proceedings. It also overlooks the fact that many Section 4 filings are not traditional rate cases, but rather filings under Section 4 to allow the pipeline to perform services in response to competitive forces.

By restricting rate filings and orders to twelve month intervals, AGD would limit rate flexibility regardless of what is happening in the marketplace. This inflexibility is especially harmful in the competitive and volatile marketplace in which pipelines currently operate. It would also put the FERC in a position of issuing orders that could be successfully attacked in the courts on the basis of not being based on reasoned decisionmaking.

The AGD proposal is utilized by certain state commissions in their rate and service regulation of local distribution companies. This regulation is predicated on franchise areas and small customers most of whom are without supply and service alternatives. The regulation of interstate natural gas pipelines in the current era of open access is predicated on transportation and supply alternatives. It would be counterproductive to this greater reliance on competition and market forces to subject interstate pipelines to the AGD proposal.

Finally, AGD greatly understates the FERC's power to act expeditiously under Section 4. It also underestimates the power of intervenors, such as itself, to expedite as well as delay settlements and final orders when to do so is perceived in the client's best interest.

Accordingly, Mr. Chairman, we strongly urge you and the Committee to reject all attempts to advance the AGD proposal relative to Section 4. We also request that this letter and INGAA's Response in Opposition be incorporated in the record of this legislation.

Sincerely,

John D. Daly

John D. Daly
Chairman

Enclosure

RESPONSE IN OPPOSITION TO AGD'S PROPOSED CHANGES TO SECTION 4 OF THE NATURAL GAS ACT

The following response is made on behalf of the Interstate Natural Gas Association of America ("INGAA") to the Associated Gas Distributor's ("AGD") proposed changes to Section 4 of the Natural Gas Act ("NGA").

INGAA is a national trade association whose membership includes virtually all of the interstate natural gas pipelines subject to the FERC's jurisdiction under the NGA. INGAA's membership also includes the major Canadian interprovincial pipelines. NGA Section 4 and its proper implementation are critical to the wellbeing of our U.S. members as well as the consuming public. The AGD proposal is the antithesis of what is needed ratewise in this era of open access and greater reliance on market forces to assure adequate supplies of natural gas at reasonable prices.

AGD has proposed that Section 4 of the NGA be amended to require that:

(1) no pipeline rate changes shall be effective until approved in a final order approving or disapproving any filed rate within 12 months of such filing;

(2) FERC shall issue a final order approving or disapproving any filed rate within 12 months of such filing; and,

(3) no rate change may be filed while a prior rate change is pending before the FERC.

AGD attempts to justify this dramatic departure from the Natural Gas Act's rate provisions on grounds of assuring a "fairer rate setting process" by reducing what it perceives as "inequities" in the implementation of the present law, a law that has been in effect for more than 50 years and upheld in countless court opinions as being protective of consumer interests. It is highly ironic that in this era of increased deregulation of the natural gas industry and reliance upon market forces to protect the public and consumer interests, AGD would seek legislative changes which would only place an increased regulatory straitjacket upon natural gas pipelines and the rates and services which they provide.

There is recognition in the pending natural gas legislation, including S. 341, that pipelines must have increased rate flexibility to respond to the sweeping changes in the natural gas industry and the intensely competitive marketplace. Yet AGD's proposal would have the precise opposite effect. Pipelines would be precluded from making rate changes designed to react to these changes and competitive pressures for a period of up to one year, and could not seek further changes, including rate decreases, until the Commission decides its prior filing.

The current Section 4 procedures have worked well in allowing pipelines to respond to competitive pressures and be creative and innovative in providing new rates and services to their customers.[1] Such changes to respond to competitive needs and other specific circumstances on a pipeline's system will be severely impaired if a pipeline must wait 12 months before it can implement any changes in its rates. Moreover, it is well recognized that pipelines face severe disadvantages with unregulated merchants, such as producers and marketers, in competing for sales to their customers. Since those parties can make rate and other changes instantaneously, pipelines should not be further disadvantaged with a 12-month delay. In addition, the AGD proposal will hinder the development of the Commission's rate design policy, since any rates reflecting these new rate design concepts can only go into effect after a final order on a pipeline's rate filing.

AGD claims that the current regulatory regime under Section 4 of the Natural Gas Act, which has been in effect for over 50 years, is somehow "broken", because pipelines have too much leverage over their customers. AGD greatly misrepresents the balance of power in the present ratemaking process. When pipelines make rate filings, they must set up financial reserves to cover the impact of any Commission decisions which disallow all or a portion of their rates.

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[1] An example of such creativity and innovation is Columbia's Off-Peak Transportation Service, which the Commission authorized, subject to refund and one-day suspension, by order issued March 1, 1991, in Docket No. RP91-82.

These reserves are audited by independent accounting firms, which can qualify their accounting statements if they believe that the reserves are inadequate. Pipelines are faced with considerable pressure to resolve rate proceedings quickly and amicably in order to avoid the buildup of reserves over time and the financial uncertainties involved with unresolved rate proceedings. Moreover, in today's marketplace the balance of power has shifted even more to the customers, because pipelines in the present era of open-access and the spot market face compelling competitive pressures to keep their rates responsive. As noted above, the AGD proposal could not have come at a more inopportune time, when the need for flexibility and competitive rates requires faster action by the pipeline industry in the ratemaking process.

It is also interesting to note that AGD's proposal is represents a warmed-over version of similar proposals that have been considered and rejected by Congress as long as 30 years ago. (See, e.g. S. 666 87th Cong. 1st Sess. (1961)). For example, in S. 666 Congress considered proposed amendments that would have prohibited a change in rates from going into effect if there was in effect an increased rate the reasonableness of which the Commission had not determined. The bill would also have imposed procedural time constraints, such as a requirement that a hearing be concluded within a year from the date of first hearing, that the presiding officer's report to the Commission be submitted within six weeks of the conclusion of the hearing, and that the Commission's decision be issued within 90 days of receipt of the report from the presiding officer. All of these proposals were rejected, except an amendment to Section 4(e) that authorized the Commission to suspend sales for resale for industrial use which formerly had not been subject to suspension.

In addition, AGD greatly understates the power of the Commission to rule expeditiously to reduce pipeline rates which it finds to be excessive. First, the Commission's suspension orders, issued 30 days after pipeline rate filings, frequently (indeed, almost always) order rate reductions when it deems certain elements of a pipeline's rates to be excessive in ways which are contrary to its policies and regulations.[2] In addition, the Commission has the authority to phase rate proceedings, and issue interim rates reductions on an expedited basis.[3] The Commission also can use rulemaking and notice and comment procedures to establish criteria for measuring the reasonableness of proposed rates.[4] Moreover, pipelines themselves have entered into interim settlements with their customers which defer or moderate rate increases while the Commission considers the merits of the rate filings,[5] and in some instances the pipelines themselves have moved to suspend the effectiveness of rate increases[6] and have placed rates into effect which are less than the original rate filing for competitive reasons.[7] And even when the pipelines place new rates into effect, they often must offer substantial discounts for transportation rates to maintain throughput on their system.

AGD asserts that similar mechanisms to its proposal have worked well at the state level for "cost of service rate cases". However, AGD provides no basis, or any criteria whatsoever for a conclusion that this mechanism has been particularly effective at the state level or, more importantly, that it is appropriate at the federal level. In implementing NGA Section 4, FERC must balance a wide diversity of interests, encompassing different regions of the nation as well as different classes of customer. Cost allocation issues which have implications by region as well as by customer classes are an example. The current settlement process at FERC is well suited to accommodate these often diverse, even conflicting interests.

Further, the AGD proposal goes well beyond traditional Section 4 rate increases. It includes all Section 4 rate filings, e.g. PGAs, other trackers and special rate filings necessary to comply with FERC policies and regulations or to respond to competitive conditions. Moreover, the current Section 4 rate procedures are working well for "cost of service" issues in pipeline general rate filings, which are frequently settled among the parties on a relatively short-term basis. The real problems and delays center upon how to divide the pipelines' costs among various services and customers. These issues, which include cost classification, cost allocation and rate design, are the thorniest, and affect the broad spectrum of intervenors in these proceedings (not just wholesale customers, but hundreds of transporters, end-users, marketers, brokers and producers), which make pipeline rate proceedings far more complex and difficult to resolve than LDC rate proceedings within the States. Moreover, these same questions of cost allocation would remain under the AGD proposal and AGD's members would be the first to appeal a FERC decision on allocation as not being based on reasoned decisionnmaking due to inadequate time for submission of data.

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[2] Colorado Interstate Gas Co., 49 FERC ¶61,169 (1989), Columbia Gas Transmission Corp., Docket Nos. RP90-108, et al., order issued May 31, 1990.

[3] FPC v. Tennessee Gas Transmission Co., 371 U.S. 145 (1962).

[4] See, e.g. Mechanisms for Passthrough of Pipeline Take-or-Pay Buyout and Buydown Costs, 53 FERC (CCH) ¶ 61,163 (1990) (Order No. 528) reh'g granted in part and denied in part, 54 FERC (CCH) ¶61,095 (1991) (Order No. 528-A).

[5] Tennessee Gas Pipeline Co., 47 FERC ¶61,254 (1989).

[6] Kentucky West Virginia Gas Company, Docket Nos. RP89-61-000, notice issued July 21, 1989.

[7] CNG Transmission Co., 48 FERC ¶61,141 (1989).

The active participation of these myriad of interests, also including state commissions, consumer advocate groups and pipeline competitors, make it virtually impossible for the Commission to issue a sound and legally supportable decision in a final order (i.e., an order on rehearing) within one year after a pipeline filing. The Commission has been frequently criticized in recent years for issuing decisions which cannot withstand judicial review. While pipelines favor expediting the ratemaking process, they cannot support legislation that will lead to poorly reasoned and unsupported rate determinations by the Commission that can only create more uncertainty during the appellate process.

Further, AGD's complaint that customers may be pressured into settlements is only a pejorative way of stating that the current ratemaking process has fostered settlements. It is in the interest of the Commission, the natural gas industry and the public to encourage settlements to resolve complicated and costly rate proceedings. Settlements are usually reached because parties, especially LDCs subject to state regulation, want to avoid uncertainties, including the uncertainty as to when a matter will be decided. If the parties know that rate cases must be decided within a one-year period it will not be possible to conduct settlement proceedings and at the same time develop an appropriate record upon which to base a decision. This will smother the settlement process and the creativity inherent therein. The parties will literally be forced to litigate.

AGD also complains that refunds are not an adequate remedy for market loss. However, there is no showing that pipeline customers are suffering market loss, and given the increased choices that customers have in this era of open access, these customers may, and do, avoid market loss by insisting upon discounts, playing the spot market, switching to other pipelines, other services, and, in the case of end-users, other fuels. Moreover, the claim that pipelines file for excessive rates in order to force "borrowing" of capital from their customers ignores the tremendous pressures that pipelines face today to keep their rates as low as possible to meet competition.

AGD's complaint about "pancaking" of pipeline rate cases is exaggerated and contrary to actual experience. Indeed, in many instances pipelines are forced to file rate proceedings which they otherwise would forego because of the three-year rule under the Commission's PGA regulations. INGAA and other parties have advocated the elimination of this three-year rule to provide pipelines with incentives for increased efficiency and productivity.

The FERC's policies favoring open access have provided enormous benefits to pipeline customers, both in terms of reduced costs and increased competitive options. Producers have also benefitted from increased marketing opportunities, and open access has spawned a new segment of our industry -- gas marketers. During this transition, pipelines have suffered sharply reduced earnings and much greater risks as they must manage their gas supply and cope with increased operational and financial challenges associated with numerous competing suppliers on their systems. Given the tremendous benefits to other segments of the industry -- including LDCs -- while pipelines face increased risks, there is no reason to impede pipelines from effectuating rate changes (nor, for that matter, by penalizing pipelines for filings to decrease rates, as Section 10004 of S. 341 provides).

Finally, it is apparent that AGD seeks to overturn the careful balancing of interest incorporated in the NGA. In this regard, the Supreme Court noted in the landmark *Memphis* case:

> It seems plain that Congress, in so drafting the statute, was not only expressing its conviction that the public interest requires the protection of consumers from excessive prices for natural gas, but was also manifesting its concern for the legitimate interests of natural gas companies in whose financial stability the gas consuming public has a vital stake. *Business reality demands that natural gas companies should not be precluded by law from increasing the prices for their product whenever that is the economically necessary means of keeping the intake and outgo of their revenues in proper balance*; otherwise procurement of the vast sums necessary for the maintenance and expansion of their systems through equity and debt financing would become most difficult, if not impossible. *This concern was surely a proper one for Congress to take into account in framing its regulatory scheme for the natural gas industry*, cf. Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591, 603, 65 S. Ct. 281, 88 L. Ed. 333, and we think that it did so not only by preserving the "integrity" of private contractual arrangements for the supply of natural gas, 350 U.S. at 344 (subject of course to any overriding authority of the Commission), but also by providing in §4 for the earliest effectuation of contractually authorized or otherwise permissible rate changes consistent with appropriate Commission review. (emphasis added).

United Gas Pipe Line Co. v. Memphis Light, Gas & Meter Division, 358 U.S. 103 at 113-114 (1958).

CONCLUSION

INGAA strongly opposes amending Section 4 of the NGA as proposed by AGD. The natural gas industry has been restructured in recent years with open access, the spot market, conversion from firm sales service to firm transportation service, and deregulation. Interstate natural gas pipelines are making timely responses to these new competitive forces. In contrast, the AGD proposal evolves from State regulation of LDCs which is predicated on specific franchise areas and customers which are generally without alternative sources of service. Therefore, INGAA urges the Committee not to attempt changes in NGA Section 4, such as those proposed by AGD (or those included in Section 10004 of S. 341), but rather provide means to encourage innovative and flexible ratemaking under existing Section 4 consistent with the new era of competition in the interstate market. Section 4, as it stands lends itself to this; the AGD proposal does not, and would be a giant step backwards into heavy handed regulation.

Written Statement of
Denise Bode
President, Independent Petroleum Association of America
Before The
Senate Energy and Natural Resources Committee
Regarding Natural Gas Legislation
Supplementing the March 7, 1991 Hearing Record
on S. 341, S. 570, and S. 741

Executive Summary

I. Provisions Supported by IPAA

- A level playing field is needed to permit fair competition between domestic and imported gas.[1] Currently, Canadian pipeline rate design provides imported gas with an artificial competitive advantage over domestic gas. DOE testified on March 7 that it merely "rubber stamps" all import applications. FERC then "defers" to DOE and refuses to exercise its jurisdiction over facilities to address the problem. This happens even thoughCongress has expressed its intention that these rate design differences be considered and that DOE or FERC attach appropriate conditions to import authorizations. Congress should reaffirm its determination to assure that free trade is fair trade and the burden of proof in an import proceeding should be on the applicant.
- "As-billed" passthrough of producer demand charges would promote domestic exploration and development on pipelines which offer comparability of sales and transportation service.[2] Currently, when a producer structures a wellhead contract to charge separately for standing ready to provide service (a demand charge), FERC policies force pipelines to collect these amounts in the pipeline's commodity rates, if at all. As a result, wellhead prices are lower, and the pipelines are reluctant to offer such payments to producers, because they run the risk of not recovering these costs. A pipeline offering reasonably comparable service should be permitted to collect producer demand charges from its customers on an as-billed basis.
- Multiple pipelines filing joint tariffs to cover a sequence of transportation could promote more efficient access to markets.[3] Independents frequently must use several pipelines to get their gas to market. If each pipeline charges a flat "postage stamp" rate regardless of length of haul, using more than one pipeline to transport gas to market can become too expensive for small producers. The combined rates can become so high as to compel

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[1] S. 741 § 713. IPAA opposes S. 570 Title II, Subtitle B which would provide competitive advantages.to imported gas.

[2] S. 741 § 713.

[3] S. 741 § 708.

producers to confine their sales to customers on the pipeline to which their gas is connected. With joint tariffs, a single lower rate could be established for transportation over a sequence of pipelines.

- Gas market demand enhancement provisions are necessary.[4] For example, an electric generation plant should be allowed to add natural gas or clean coal technology (which will lower its emission levels) without falling under the new source performance requirements of the Clean Air Act.[5]
- New statutory provisions to encourage growth in gas demand, including PUHCA reforms to encourage gas-fired independent power producers should be adopted.[6]
- Congress should provide an antitrust exemption for small producer marketing cooperatives.[7] This would help independents aggregate larger packages of gas necessary to compete in the marketplace.

II. Provisions Opposed by IPAA

- IPAA opposes deregulation of the pipeline merchant function. Pipelines are natural monopolies, and provisions which permit them to control access to markets without regulatory oversight will harm independent producers.and consumers.[8]
- Legislation which deregulates new pipeline construction if the pipeline's investment is "at risk" will not work unless pipeline is truly at risk. At present, when an investor proposes a new pipeline, the FERC reviews the plan to ensure that the pipeline is appropriate for its gas supplies and markets. This is intended to prevent developers from overbuilding unnecessary pipeline facilities at ratepayer expense. In order to promote new pipeline construction, some proposals would eliminate this review process if the investor is willing to assume the risk that the project will not be fully used in the future. Because of the technical difficulty in defining how the investor will be placed at sufficient risk to deter unnecessary projects, perhaps this issue is best left to FERC as a regulatory matter. Any "at risk" requirement should be for the life of the project, and not just for a few years, with the prospect for a ratepayer bailout if the project's economics go sour.[9]

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[4] S. 741 Title VII;

[5] S. 341 § 5101.

[6] S. 341 Title XV (exemption from Public Utility Holding Company Act.)

[7] S. 341 § 10007.

[8] S. 570 § 205, particularly ¶ g. S. 741 § 710-711 avoids some of the problems of the S. 570 language, but is still troublesome.

[9] S. 570 § 205, particularly ¶ k. S. 341 § 10001(d) would permit a pipeline to eliminate its risk and roll in the cost of expanded facilities after 10 years.

III. Additional Matters Which Should Be Addressed in the Legislation

- FERC should be given "teeth" to successfully implement a balanced natural gas strategy which will encourage domestic exploration and development, including transfering Section 3 of the Natural Gas Act (gas imports) from DOE to FERC. From 1938 to 1977, FERC and its predecessor the FPC, regulated all aspects of gas imports under the Natural Gas Act. Since 1984, DOE has had the complete authority to regulate imports, but has chosen not to create a level playing field between domestic and imported gas. These responsibilities should be returned to FERC[10] to assure that all gas suppliers receive fair treatment from federal regulators. Other statutory provisions clarifying that FERC has authority to set rates and grant certificates by rulemaking may also be helpful.[11]
- A legislative framework requiring public utility commissions to encourage open access at the state level is needed. FERC's open access transportation program requires pipelines to offer transportation to all if transporting for anyone. This provides producers with multiple markets for their gas and consumers with a choice of suppliers. However, many local distribution companies (LDCs), which are regulated by the states, do not have similar requirements. Hence, LDCs can exercise monopoly power over competitors for end-use markets. The benefits of open-acess transportation should be extended to LDCs.
- FERC's jurisdiction over the brokering of interstate pipeline capacity by LDCs should be clarified. Currently FERC regulates the allocation of interstate pipeline capacity. Some LDCs are proposing to broker their capacity on interstate pipelines to end-users. The FERC is more likely to implement procedures with a national focus than the state public utility commissions that are subject to state and local pressures. Although FERC has jurisdiction over these matters, the state commissions are challenging FERC on this point. Clarifying legislation will avoid a protracted controversy.
- The Congress should mandate that each interstate pipeline file a new Section 4 general rate case at least once every three years. This is appropriate because such filings are currently required by regulations subject to waiver.

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[10] S. 570 § 221 would establish a Natural Gas and Electricity Administration within DOE. FERC is now an independent regulatory agency. Regardless of whether FERC remains an independent agency, the same entity responsible for regulating domestic pipelines should be responsible for regulating gas imports, in order to assure a level playing field.

[11] E.g., S. 341 § 10005.

Written Statement of
Denise Bode
President, Independent Petroleum Association of America

Issue by Issue Analysis

Thank you for providing the Independent Petroleum Association of America (IPAA) with the opportunity to present its views on the natural gas provisions of **the Johnston-Wallop Bill (S. 341)** and **the National Energy Strategy Act (NESA) (S. 570)**, which are the subject of the Committee's March 7 hearing. IPAA has testified separately on other sections of this important legislation. This testimony also addresses **the Wirth-Hatfield Bill (S. 741)**, which was introduced after the March 7 hearing.[12]

1. Background on IPAA and the Interests of Independents

The Association represents independent crude oil and natural gas producers in all 33 states with oil and natural gas production. Independents drill the overwhelming majority of all U.S. wells and find more than half of the nation's new oil and natural gas reserves. Independents operate as individuals, partnerships, or public corporations, ranging in size from very small, one-person ventures to large firms with hundreds of employees engaged in extensive oil and natural gas exploration, development and production. According to a recent study, independents derive 48% of their revenues from domestic natural gas. Small, privately-owned oil and gas companies represent about 40% of our nation's natural gas production. Accordingly, the natural gas provisions of these bills are of particular importance to independents, and in turn, the fate of the independent gas producer is of particular importance to the nation's quest for energy stability and self-sufficiency.

2. Background on the Need for Regulatory Reform

The natural gas industry has changed rapidly, and the statutory and regulatory structure must keep pace with those changes. In the mid-1970's the natural gas industry was hampered by a dual intrastate-interstate market, with artificial wellhead price controls hampering new gas supplies from reaching the interstate market. The Natural Gas Policy Act of 1978 (NGPA) began the deregulation of wellhead prices and created a nationwide transportation network across both intrastate and interstate pipelines. Gas producers responded by increasing the deliverability of supplies.

During the period of natural gas curtailments, FERC adopted rate structures which were designed to discourage industrial and utility gas consumption. Although FERC has made minor changes in its rate structures since the end of curtailments, it has failed to adopt rate policies which will enhance the ability of natural gas to compete for industrial and utility markets. The net effect of the cumulative policies of FERC and the state commissions has been to discourage industrial and utility gas consumption, harming consumers and producers alike by reducing throughput in a time of surplus. These policies have also reduced the economic and regulatory stability at the wellhead necessary to justify continued healthy development of the domestic gas resource base. Although these policies were intended to protect residential consumers, the net effect of the lower total consumption of natural gas has been to shift a greater portion of transmission and distribution cost onto residential and commercial customers.

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[12] Sen. Wirth also introduced S. 662, "The Gas Policy Reform Act" on March 14, 1991. The provisions of S. 662 are included in S. 741.

The best solution for this problem is to adopt legislative and regulatory initiatives which will promote growth in the natural gas industry, both at the burnertip and the wellhead. In this manner, the nation can enjoy not only the environmental benefits of natural gas, but the economies of scale that would result from more efficient utilization of the gas industry infrastructure as well.

3. The Need for a Level Playing Field for Imported Natural Gas

The NESA, S. 570, ignores a major problem which has limited reliance on the nation's exploration for, and development of natural gas supplies. Because of rate design differences between United States and Canadian pipelines, domestic gas is at a competitive disadvantage when competing with Canadian gas. Canadian pipelines are allowed to recover a greater portion of their fixed costs in demand charges than are allowed by FERC which regulates domestic pipelines. Because gas distributors make their purchasing decisions based on a comparison of commodity rates, the Canadian gas appears to be less expensive than domestic supplies, even though the total cost of the Canadian gas (taking into account both demand and commodity charges) can be more expensive.

Since 1938, prior approval by the Federal government has been required to export or to import natural gas. The NESA proposes to repeal Section 3 of the Natural Gas Act and deregulate natural gas imports. The Department of Energy's March 7 testimony offers two rationales for this proposal. First, there is a general advocacy of deregulation with the government staying out of the way of "consenting adults" who reach an agreement.[13] Second, DOE characterizes its current approach toward implementing Section 3 as being a "rubber stamp" and sees the repeal of Section 3 as merely removing an unnecessary layer of regulation.[14] Neither argument justifies the repeal of Section 3.

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[13] Tr. 12, March 7 Hearing.

[14] Tr. 42.

On the first point, the fact is that the people who bear the cost of imported natural gas — the end-users — are frequently not a party to the agreement at the border. Thus, in many cases, they do not actively consent or play a role in negotiating the terms of the border contract. Instead, the importing local distribution company, who in many cases has an equity interest in the importing pipeline,[15] will negotiate the terms of the import transaction to maximize the utilization of their facilities, rather than attempt to secure the lowest price for the imported gas.

On the second point, since the enactment of Section 3 of the Natural Gas Act in 1938, the provision has served an important regulatory function and prevented an "attractive gap" in the regulatory scheme. Prior to the creation of DOE, Section 3 was administered as an integral part of the Commission's oversight of the portion of the natural gas industry which was not subject to state control. Prior to the enactment of the NGPA, all sales for resale in interstate commerce were subject to the rate and certificate jurisdiction of the Commission under the Natural Gas Act. Thus, a single uniform approach was applied, and FERC's Section 3 authorization was deemed to cover any sale for resale which occurred at the border.

In 1978, Congress made a determination that the wellhead market for natural gas was competitive and began a transition from utility regulation of such sales toward decontrol. The subset of jurisdictional sales for resale defined as "first sales"[16] were subject to decontrol. The NGPA, as amended by the Wellhead Decontrol Act of 1989,[17] will deregulate all "first sales" by 1993.[18] "First sales" are any sales for resale which precede a pipeline, distributor, or end-user taking title to natural gas.

Sales for resale downstream from the pipeline are not "first sales" and remain subject to FERC certificate and rate jurisdiction. Congress did not then, nor does it now, have a factual basis upon which to conclude that these downstream markets are competitive enough to warrant deregulation. Yet, that is precisely what S. 570 would do. Not only would it repeal Section 3 of the Natural Gas Act (thereby depriving any Federal administrative agency of supervision of border transactions), but it would remove jurisdiction over any subsequent sale for resale of imported gas, including *all* sales downstream of the pipeline.[19] It would also preempt both Federal and State review of the purchasing practices of the imported gas purchases.[20] S. 570 does not preempt State review of local distribution company purchasing practices of domestic gas, thus giving a further competitive advantage to imports.

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[15] For example, Pacific Gas & Electric owns Pacific Gas Transmission, the pipeline which connects its system to Canada. A group of Northeast distributors own a 31% equity share of the Iroquois Gas Transmission System.

[16] NGPA Section 2(21), 15 U.S.C § 3301(21).

[17] P.L. 101-60, July 26, 1989.

[18] NGPA Section 121, 15 U.S.C. § 3331.

[19] S. 570 § 213 would enact this as a new §3(a) of the Natural Gas Act.

Prior to the transfer of Section 3 authority to the DOE, the factors considered in authorizing imports included: the security of supply, the effect on U.S. balance of payments, the price proposed to be charged, the effect on proximate domestic supplies, and the need for the gas.[21] These remain valid elements of the public interest, although they have been brushed aside by DOE on the grounds that "competition" somehow supplants these traditional regulatory concerns.[22] Yet, the fact remains that domestic "competition" with Canadian gas is based on a regulatory scheme which discriminates against domestic suppliers and the U.S. trade deficit has grown more severe due to our dependence on foreign energy, as indicated by Attachment A. Similarly, despite years of litigation before the FERC and the Courts both in pipeline rate proceedings as well as an endless stream of rulemakings, the promise of a truly competitive North American gas marketplace has yet to be realized. As a result, when DOE relies upon competition in the burner tip gas market to supplant direct regulation of imports, it merely invites the import sponsors to abuse even more the current regulatory system with a series of "rate gimmicks" which take advantage of an unlevel playing field between domestic and imported supplies.

FERC and the Courts have previously recognized this problem and adopted Opinion No. 256[23] which permits FERC to modify the demand/commodity split of imported gas costs when regulating resale rates within the United States. As drafted, S. 570 would remove FERC's jurisdiction to make such adjustments, because that would "treat ... imported natural gas *while it is within the United States* differently than any other natural gas." The policy goal adopted in Opinion No. 256 by the FERC, and endorsed by independent producers, was to create a "level playing field" between United States and Canadian natural gas. The fact that Canadian natural gas is treated differently north of the border must be taken into account if such a level playing field is to be established. Yet, S. 570 requires FERC and the State Commission to disregard such facts and would ensure and perpetuate discrimination against domestic gas in mandating so-called equal treatment

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[20] S. 570, new §3(b). Also, as a "first sale" such gas costs would be guaranteed passthrough under NGPA § 601, 15 U.S.C. § 3431.

[21] West Virginia Public Service Comm'n v. DOE, 681F.2d 874, 851 (D.C. Cir. 1982); Distrigas Corp. v. FPC, 497 F.2d 1057, 1065 (D.C. Cir. 1974), cert. denied, 419 U.S. 834 (1974).

[22] New Policy Guidelines and Delegation Orders from the Secretary of Energy to Economic Regulatory Administration and Federal Energy Regulatory Commission Relating to the Regulation of Natural Gas, 49 Fed. Reg. 6,684 (1984).

[23] Natural Gas Pipeline Co. of America, 37 FERC ¶ 61,215 (1986), rehearing, 39 FERC ¶ 61,218, aff'd sub nom. TransCanada PipeLines Ltd. v. FERC, 878 F.2d 401 (D.C. Cir. 1989).

"within the United States." Title II, Subtitle B of S. 570 would prevent the government from eliminating the distortions created by foreign rate designs and should not be adopted. Instead, we believe that a provision similar to § 714 of S. 741 would promote a level playing field and should be adopted.

A second problem with S. 570 is that it would provide the President with greater authority to set timetables or waive statutory requirements for imported gas projects. This authority does not exist, nor was it recommended by the administration, for new domestic gas projects. Proposed Section 3(d) of the Natural Gas Act would provide:

> Upon finding that the exportation or importation of natural gas is in the national interest, the President may waive any law relating to the exportation or importation of natural gas or may specify, by schedule or otherwise, when a particular law relating to the exportation or importation of natural gas is considered satisfied if the appropriate Federal or State agency has not taken final action.

There is no policy basis for providing the President with this authority solely for import and export projects. At present, the President has ample emergency authority under Title III of the NGPA, without regard to whether gas is of imported or domestic origin. Similarly, FERC has authority to act in emergencies under Section 7(c) of the Natural Gas Act. Independent producers do not see a need for additional emergency authority at this time.

IPAA agrees with DOE's assessment, at least in the context of the current regulation of imports, that "the current system of regulation needs a major overhaul, not just tinkering around the edges."[24] However, IPAA's recommended overhaul would be to transfer all authority over imports from DOE back to the Commission so that a single body could adopt a uniform set of policies over both domestic and imported gas, thereby giving the Commission full and undeniable authority to create a level playing field.

Instead of adopting legislation which would further harm domestic producers, Congress should promote a goal on which we can all agree, i.e. reduction of reliance on imported oil. Establishment of a level playing field for domestic and imported natural gas will encourage reliance on gas, while adoption of the Administration's natural gas import provisions will back-out as much or more domestic gas as imported and domestic oil, exacerbating rather than reducing our balance of payments problem. Instead of the S. 570 provisions, IPAA recommends adoption of § 714 of S. 741. This provision would require import authorizations to be conditioned "upon action by the Commission to redress any anticompetitive impacts on United States gas producers including, but not limited to, competitive disparities resulting from different rate designs applied to the transportation of domestic gas and imported supplies." Two additional drafting points should be considered in crafting a solution to this problem. First, a provision should be added to clarify that the burden of proof in any Section 3 proceeding should be on the applicant. Second, this "level playing field" condition should apply to both existing and new import authorizations, not just "the approval of any import application." In this manner, the Commission (or the Secretary of Energy, if authority is not transfered from DOE) would have an affirmative duty to level the playing field with respect to existing as well as new import authorizations.[25]

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[24] Tr. 12.

4. "As-billed" Passthrough of Producer Demand Charges Can Contribute to a Level Playing Field

Certain provisions, such as Section 713 of S. 741, would provide domestic producers with the opportunities currently afforded foreign producers, i.e., the opportunity to recover some of their costs in pipeline demand charges. At present, FERC ratemaking policies require interstate pipelines to recover all domestic producer payments in commodity rates, while foreign producers are allowed to negotiate demand charge recovery of a portion of their wellhead revenues. In addition, marketers and distributors reselling gas purchased under two-part wellhead prices are not subject to the requirement of commodity-only recovery. These policies have two adverse results. First, given the historically predominant role of interstate pipelines as purchasers in the wellhead market, if they are unable to pass through producer demand charges on an "as-billed" basis, it is unlikely that such contracts will gain widespread acceptance in the industry. Second, the ability of non-pipelines to offer such contracts may tend to undermine the ability of interstate pipelines to continue to serve a merchant function.

In general, IPAA supports the approach taken in § 713 of S. 741. It would require "as-billed" passthrough of producer demand charges unless the Commission determines, after a hearing, that the reselling interstate pipeline does not offer a reasonably competitive transportation alternative to its sales service. IPAA believes that comparablility of service between pipeline sales and transportation functions is an essential element in restructuring pipeline services and that pipelines which fail to offer reasonably comparable service should not be entitled to as-billed passthrough of two-part producer rates. We understand that this provision would place the burden of proof on the party challenging the as-billed flow through of the demand charge. As drafted, § 713 would provide this benefit to any "first sale" of natural gas, as that term is defined in § 2(21) of the NGPA. Because FERC retains the right to disallow such first sale costs upon a showing of favoritism toward affiliated purchases or "fraud, abuse or other similar grounds," FERC can exercise overall supervision of any abuse of this two-part rate form in extreme cases of market failure.

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[25] Because DOE has adopted the practice of issuing blanket import authorizations which do not become effective until the date of first deliveries, there is a large inventory of approved, but unused import authorizations. If the § 714 condition were to apply prospectively only to new authorizations, this large inventory of Section 3 authorizations would represent a serious loophole which would thwart the intent to establish a level playing field.

Producer demand charges can be particularly important in cases where gas is sold to electric generation customers. Since most power pools dispatch power based upon lowest variable cost, a gas supplier with a lower commodity rate can guarantee that its electric generation customer will be brought on line in preference to other plants which might pay for gas supplies of equal cost on a commodity-only basis.

5. Market Enhancement Legislation is Needed.

Natural gas consumption has declined from a peak of 21.7 Tcf in 1971 to 16.2 Tcf in 1986. Preliminary figures indicate consumption of only 18.5 Tcf in 1990. Given the environmental and cost benefits of natural gas (which sells at a significant discount to the Btu equivalent price of imported oil), national consumption should have increased. In addition, the abundant, proven domestic reserve base of gas is an additional advantage which would warrant vastly increased consumption. However, governmental policies, motivated by a concern in the 1970's that gas must be conserved to prevent shortages, inhibited the natural growth of gas markets. Congress can reverse this trend by enacting legislation to facilitate the increased use of natural gas. For example, the provisions in both S. 341 and S. 741 which provide for exemptions from the Public Utility Holding Company Act for independent power producers can assist in increasing the natural gas share of the electric generation market.

6. Small Producer Marketing Cooperatives Should Be Exempt from Antitrust Laws.

Traditionally, natural gas was sold under long term contracts to whatever pipeline was closest to a particular well. The well operator would typically market the production of minority working interest owners under its gas sales contract with the pipeline. In addition, state regulation to protect the rights of all interest owners in a well or field tended to assure that small producers would receive equal treatment with larger producers in gaining markets for their gas. Unfortunately, with the abrogation of long-term contracts and the current market dominated by spot-market arrangements, small producers are at a considerable disadvantage in marketing their production. For example, some pipelines impose onerous balancing tolerances and some purchasers set minimum volumes for the packages of gas which they are willing to purchase. For this reason, IPAA supports the antitrust exemption for small producer marketing cooperatives proposed in Section 10007 of S. 341.

We have one drafting concern with Section 10007. As drafted, it would merely exempt such cooperatives from *per se* antitrust doctrines. However, participants in such cooperatives could be still subject to costly fact-specific litigation upon the allegation that "the anticompetitive effects substantially outweigh the procompetitive effects" of the particular cooperative. The bill does not define whether this inquiry would be made in the context of a national gas market or if some local market definition would apply. Independent producers would favor an unconditional exemption for such cooperatives, based upon the fact that a competitive wellhead market for gas would exist, even if every eligible small producer joined a cooperative. This is evident from the number of producers who are too large to be eligible to join a cooperative under the proposed 6,000 Mcf/day quailification standard. Regarding the qualification standard, IPAA believes that an annual, rather than daily, volume of production is a more reasonable basis for determining eligibility. Given the current market, some producers may have production shut in for a significant portion of the year, and a daily measure might disqualify a number of producers with a minor overall participation in the gas market. The level of an annual qualification standard requires further analysis of actual production data, and IPAA will make additional recommendations at a later date.

In sum, IPAA believes that a general antitrust exception rather than the limited relief afforded by § 10007(b) would be most appropriate.

7. Section 4 Rate Reform

Independent producers are more vulnerable than other segments of the industry to pipeline overcharges. The gas production of independents is typically priced on a "net-back" basis, so that any increase in pipeline transportation charges usually reduces wellhead revenues. At present, a pipeline is free to file an excessive rate increase request with FERC. Because FERC has only 30 days in which to act on the proposal, it provides a very short period for public comment. Because pipelines are required to serve their sales customers and state commissions with rate filings, other elements of the gas industry have advance notice of these proposals. However, producers and other shippers do not have the benefit of these requirements and sometimes must respond to a Federal Register notice of a pipeline rate filing on the day of publication. For this reason, we support the proposal to provide FERC 60 days to act on such rate filings, with the expectation that the change would provide for a longer public notice period.

In addition, at present, FERC's authority to order refunds is limited to the extent of a rate increase, even if the previously filed rates were unreasonably high. We support the proposed amendment which would authorize FERC to order refunds down to the levels determined to be just and reasonable without regard to the previously effective rates.

8. Section 311 Construction.

Section 716 of S. 741 would codify existing law that facilities used exclusively for Section 311 transportation are not subject to Natural Gas Act jurisdiction. It would also make explicit the requirement that the constructing pipeline must participate in open access transportation. We are troubled that the provisions of both S. 341 and S. 570 on this point would render such construction jurisdictional in the process of granting the Commission the ability to authorize it by rule or order. The better course would be to retain the non-jurisdictional status of Section 311 construction.

9. Section 311 "on behalf of" test.

We favor elimination of the "on behalf of" limitation for all Section 311 shippers. Gas markets will function most efficiently if the greatest number of possible buyers and sellers are permitted freedom to structure transactions on a level playing field. At present, the shipper in a transportation arrangement receives any rate refunds ordered by the Commission. Because of the "on behalf of" test, producers frequently must structure their transportation agreement to designate a distributor as the shipper. As a result, producers whose netback gas revenues are determined by pipeline transportation rates do not automatically benefit from subsequent refunds of overcharges.

10. "At Risk" Construction

Various bills would permit pipelines to construct facilities without the traditional regulatory review and authorization if the investors are "at risk." Historically, FERC has found enforcement of such "at risk" conditions difficult to impose in any meanigful way. Any "at risk" condition accepted by a pipeline in its certificate proceeding is the target of repeated attempts to erode the condition in subsequent pipeline rate cases or to seek modification of the certificate based upon "changed circumstances." Any at risk condition must be for the life of the project if it is to succeed in bringing the discipline of the marketplace to bear in preventing uneconomic pipeline construction.

There is a natural tension between simple, system-wide transportation rates and various "optional certificate" procedures. On the one hand, producers want as simple a regulatory system as possible, including stable rules for preventing undue discrimination. On the other hand, if a pipeline has a bottleneck, it makes sense for parties willing to pay to expand capacity at that bottleneck to have priority of service through the new facilities.

Any policy which addresses this problem must also address who "owns" the right to the cheap expansibility of an existing pipeline system. (The cost of expanding capacity on a pipeline varies depending upon how much expansion has occurred before.) Perhaps such complex issues are best left to FERC's discretion. We are concerned that legislation creating optional procedures may inadvertently prejudge this issue in a manner which may favor one segment of the gas industry over another.

11. Open Access at the State Level

A number of states are implementing capacity brokering plans for their distribution companies. Some state commissions are also attempting to assert jurisdiction over the manner in which their distributors broker interstate pipeline capacity. This raises the potential for undue discrimination against shippers who compete with local distribution companies when making sales to end-users. Legislation is needed which would encourage states to establish open-access transportation or would encourage DOE to become active in state proceedings to foster open-access (See 42 U.S.C. §7133(a)(6) and (7).)

The Congress can also reconfirm that FERC has exclusive jurisdiction over the brokering of jurisdictional pipeline capacity, and that state action cannot remove that authority.

In addition, the Congress can express its intent that LDCs which seek to avail themselves of the benefits of open access transportation should have the obligation to afford the same option to their end-user customers as well.

12. Deregulation of the Interstate Pipeline Sales Function

In addition to deregulation of imported natural gas without a hearing, § 205(b) of S. 570 would provide for a permanent deregulation of the interstate pipeline sales and transportation into a given market after a one-time hearing to demonstrate that competition for that market exists and that the pipeline's sales and transportation services are offered in that market on a not unduly discriminatory basis. Section 710 of S. 741 would deregulate sales for resale in such circumstances. Similarly, § 711 of S. 741 would deregulate new services "which can be fully supplanted with other preexisting services" which remain jurisdictional.

Independent producers do not believe that the factual basis for deregulation of city-gate markets exists at this time. Certainly, the Congress should not undertake initiatives to deregulate city-gate markets without first assuring that producers will have equal access to end-user markets located behind those city-gates. Otherwise, the monopoly power of the local distribution companies will fill the void left by deregulation.

In terms of drafting, § 710 of S. 741 is preferable to S. 570 because it provides the Commission with an opportunity to condition its decontrol determination and the right to revoke the determination. In contrast, under S. 570, once the Commission makes its finding, the service would be permanently deregulated, even if circumstances change. A second important difference is that S. 570 would deregulate either the transportation service to the customer, the sales service to the customer, or both. In contrast, S. 741 would deregulate just the sales service. (It is difficult to imagine how comparability between sales and transportation service would be maintained if the Commission deregulated either sales or transportation without imposing conditions.) Assuming that the deregulation of sales service can be justified based upon the availability of multiple sellers operating under open access, a similar rationale is not available for the deregulation of *transportation*. Unless there is a significant amount of excess pipeline capacity serving a particular market, interstate pipelines will continue to hold monopoly power regarding their transportation service. This makes regulatory oversight essential.

Section 711 of S. 741 poses fewer difficulties if the term "fully supplanted" is defined with reasonable care. Given the past litigation over tariff availability clauses and "full requirements" conditions, pipeline tariffs could be constructed to force users to purchase the deregulated alternative because the regulated one is not made available as a practical matter. Unless the shipper/purchaser is free to choose any combination of regulated and deregulated service, it is possible that the rights afforded to the interstate pipelines under § 711 could be abused.

13. General Section 4 Rate Cases Should Be Required At Least Once Every Three Years.

General Section 4 rate cases protect the customers of a pipeline by assuring that the pipeline's costs and rate revenues are brought into balance. They also provide a forum in which to reassess the terms and conditions of pipeline service. If the Congress amends Section 4 to permit refunds to levels below previously effective rates, interstate pipelines will be reluctant to file for rate decreases under Section 4. At present, the Commission requires as a precondition for maintaining a Purchased Gas Adjustment Clause (PGA) that each pipeline holding a PGA must file a general Section 4 rate case at least once every three years. Thus, the widespread industry practice is to file rate cases at least this frequently. However, many pipelines are surrendering their PGAs in exchange for implementing gas inventory charges. As a result, a growing number of interstate pipelines will no longer be subject to the three year rate filing requirement. A statutory provision would provide FERC with authority to mandate such filings. Of course, the Commission should be afforded discretion to waive the requirement in appropriate cases.

Conclusion

IPAA appreciates this opportunity to comment on these natural gas bills and looks forward to working with the Committee as it develops a more efficient and responsive federal natural gas regulatory environment.

NATURAL GAS SUPPLY ASSOCIATION

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Nicholas J. Bush
President

SENATE [illegible]

March 28, 1991

The Honorable Bennett J. Johnston
SH-136, Hart Senate Office Building
United States Senate
Washington, D.C. 20510

Dear Senator Johnston:

The Natural Gas Supply Association (NGSA) welcomes the opportunity to comment on S. 341 and S. 570 and in particular on the natural gas provisions of these bills. NGSA is an association of companies engaged in the exploration, production and marketing of natural gas throughout the United States. NGSA members produce and market approximately 90% of all domestic natural gas.

Attached are NGSA's comments that focus upon Title X of the National Energy Security Act of 1991 and Title II of the National Energy Strategy Act. As we have noted in prior testimony and communications to Congress, NGSA also strongly supports the passage of those provisions in these bills that would amend the Public Utility Holding Company Act and would establish access to the Alaska National Wildlife Refuge. While reforming the regulatory aspects of natural gas law is timely and important, it is as critical that direct opportunities for greater domestic natural gas production and use be pursued. Reform of the Public Utility Holding Company Act, as well as expanded programs for alternative fuels, would benefit not just natural gas but other fuels as well. The important point is that the nation's energy and economic outlook will be enhanced by the greater reliance on domestic fuels.

The enclosed comments address five specific issues: the certification of pipeline construction and operation, proposed reorganization of the Federal Energy Regulatory Commission, administrative and judicial review of Commission decisions, vehicular natural gas and deregulation of pipeline sales and transportation.

We would commend to your attention especially NGSA's position on certificate reform. NGSA believes that distinct legal status should be granted to "at-risk" facilities, i.e., projects which rely primarily on market forces and private negotiation -- not regulation -- to establish rates and allocate risks. Any entrepreneur should be able to build and operate an "at-risk" facility without falling subject to the full array of cost-of-service regulation. Wherever possible, the rates, terms and conditions for services on "at-risk" facilities should be negotiated between potential shippers and the facility operator without Commission intervention. In addition, NGSA advocates mandatory interconnection as an indispensable means of assuring that "at-risk" developers will be able to gain access to the interstate transportation grid.

Representing the Nation's Producers of Natural Gas

The positions expressed in this paper reflect the general consensus among NGSA's members. If you or your staff members have any questions regarding any position, feel free to call me or John Sharp, NGSA Director of Congressional Affairs at (202) 331-8900.

Sincerely,

Nicholas J. Bush

NJB/jt

cc: The Honorable John D. Dingell, Chairman, Energy & Commerce Committee, U.S. House of Representatives

The Honorable Philip R. Sharp, Chairman, Energy & Power Subcommittee, House Committee on Energy and Commerce, U.S. House of Representatives.

The Honorable Martin L. Allday, Chairman
Federal Energy Regulatory Commission
The Honorable Elizabeth Ann Moler, Commissioner
Federal Energy Regulatory Commission
The Honorable Charles A. Trabandt, Commissioner
Federal Energy Regulatory Commission
The Honorable Jerry J. Langdon, Commissioner
Federal Energy Regulatory Commission
The Honorable Branko Terzik, Commissioner
Federal Energy Regulatory Commission

Enclosure

COMMENTS OF THE
NATURAL GAS SUPPLY ASSOCIATION

WITH RESPECT TO TITLE X

OF THE

NATIONAL ENERGY SECURITY ACT OF 1991

AND

TITLE II OF THE

NATIONAL ENERGY STRATEGY ACT

MARCH 27, 1991

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NGSA'S EXECUTIVE SUMMARY

NGSA offers the following positions with respect to natural gas reform:

1. CONSTRUCTION CERTIFICATION

A. Any person should be permitted to construct an "at-risk" facility, including producers, marketers and any other private entrepreneurs. Construction and operation should not be limited to "natural gas companies," i.e., existing interstate pipelines.

B. A right of mandatory interconnection is indispensable to any legislation in both the market area and the supply area. Mandatory interconnection proceedings should provide for parties to select mutually agreeable sites where possible, but interconnecting pipelines should not be required to expand their existing system capacity or divest their existing customers' contract rights.

C. Rates, terms and conditions for service on "at-risk" facilities should be negotiated between potential shippers and the facility operator. However, protective remedies and procedures should be available to potential shippers who are subjected to undue discrimination or unreasonable denial of access.

D. Developers of "at-risk" facilities should have the option of either obtaining a pre-construction certificate covering all phases of development, or proceeding without certification.

E. Existing certification under Section 7(c) of the Natural Gas Act should be preserved as an option for parties seeking traditional construction authorization and rates approved by the Commission as just and reasonable. Under certain strict criteria, "at-risk" facilities may be converted into traditional rate base facilities after ten years of operation.

F. NGPA Section 311 should be amended to modify the "on behalf of" test. To avoid confusion and overlap between construction under Section 311 and "at-risk" construction under the non-certificated option, Congress should limit interstate pipeline construction under Section 311 to incidental facilities which help bridge the interstate and intrastate markets.

2. COMMISSION RESTRUCTURING

The Commission should remain a distinct entity apart from the Department of Energy. By placing Commission matters into a larger, more politicized body, the proposed restructuring would work against expeditious decisionmaking and independent analysis.

3. ADMINISTRATIVE AND JUDICIAL REVIEW OF COMMISSION DECISIONS

A. The Commission should have unconditional authority to toll the issuance of rehearing order for a maximum of 120 days.

B. The time for filing petitions for judicial review should be shortened to 45 days; however, petitioners should not be required to specify the issues for court review.

C. Once the administrative record has been filed with a reviewing court, that court should retain exclusive jurisdiction over the Commission order at issue.

D. The notice period before a rate change goes into effect should be extended to 60 days for rate increases, and reduced to one day for rate decreases.

E. Pipelines should be required to file rate cases periodically (perhaps every three years). A refund obligation should attach on the filing date, and obligate the pipelines to return all amounts collected in excess of whatever rates are judged by the Commission to be just and reasonable.

F. The Commission has and must continue to have the authority to establish rates, issue certificates and authorize service abandonments through rulemaking.

4. VEHICULAR NATURAL GAS

Sales of compressed natural gas should be free of all economic regulation, including regulation by the states. Federal legislation should therefore expressly pre-empt state regulation.

5. DEREGULATION OF PIPELINE SALES AND TRANSPORTATION

Pipeline sales should not be statutorily deregulated in light of the continuing lack of comparability between pipeline transportation service and the transportation component of pipeline sales service; pipeline transportation should not be deregulated under any foreseeable circumstances in view of the pipelines' continuing monopoly power.

ISSUE BY ISSUE ANALYSIS

1. CERTIFICATE REFORM

Overview.

Consistent with the goal of encouraging increased natural gas utilization, NGSA strongly supports measures which remove or streamline some of the regulatory impediments caused by existing law. In comments to the Federal Energy Regulatory Commission's proposed rule on certificate reform (see attached) NGSA has recommended innovative approaches to expediting new pipeline construction. NGSA tailored those rulemaking comments to accommodate existing statutory boundaries, but those comments are equally responsive to most of the proposals contained in Title X of S. 341 and Title II of S. 570.

NGSA believes that any certificate reform legislation should satisfy the following fundamental requirements:

1. Remove current barriers to entry by permitting anyone, not just existing interstate pipelines, to construct "at-risk" facilities;
2. Grant distinct legal recognition of "at-risk" facilities, i.e., projects which rely primarily on market forces and private negotiation -- not regulation -- to establish rates and allocate risks;
3. Establish standards of conduct and clear-cut procedures which promote and preserve competition among operators and potential shippers on "at-risk" facilities.

From an overall perspective, NGSA believes that any new natural gas legislation should focus on providing basic ground rules which will promote the construction of new natural gas pipeline facilities on an expedited basis. However, certificate reform is not simply a matter of getting more pipe in the ground, for the cost of inefficient, unjustified construction will be borne by all segments of the natural gas business. The national interest will not be served by a proliferation of economically wasteful facilities, and NGSA therefore recommends a balanced reform package which will promote both competition and efficiency in new construction.

Although NGSA is recommending certain deletions, modifications and additions to these bills, NGSA supports their underlying objective of promoting increased availability and usage of natural gas for domestic consumption. NGSA therefore welcomes the opportunity to present the proposals detailed below, together with comments on the corresponding elements of S. 341 and S. 570.

What is an "At-Risk Facility?"

Both bills embrace the fundamental premise that existing entry barriers to pipeline construction can be substantially reduced if new facilities can be built on an "at-risk" basis in lieu of traditional certification.

Under existing procedures, the construction and operating costs of traditional pipelines are usually rolled into the pipeline's rate base and cost of service, respectively, and these costs are then allocated among the pipeline's customers. This traditional approach departs from market realities in at least three significant ways. First, there is no direct connection between a customer's cost responsibility and its use of the new facilities. In addition, the traditional pipeline is not "at-risk" if its costs are greater than anticipated, since those extra costs can be recovered in subsequent rate filings, Finally, the traditional ratemaking approach incorporates a profit increment reflecting a reasonable opportunity for the pipeline to earn a fair return on its construction investment.

In contrast, an "at-risk" project is defined by the willingness of private parties to respond to market forces and assume market risks. Under the "at-risk" approach, a pipeline developer and its subscribing customers use arms-length agreements to allocate cost responsibility and share the risks of underutilization and cost underrecovery. Non-subscribing customers pay nothing toward the project. Subscribing customers pay no more than they contract to pay.

Consistent with a non-market, regulatory approach to cost recovery and profit, traditional certification proceedings often go to great lengths to determine whether a proposed project is economically sound. In contrast, the economic value of an "at-risk" project is determined by market demand, as measured by customers' willingness to contract for service. This critical distinction provides the basis for granting "at-risk" facilities the unique legal treatment described below.

Finally, NGSA urges that an option be made available for existing, non-certificated gathering facilities to be converted into "at-risk" interstate facilities. Title X of S. 341 envisions encouraging new construction of interstate facilities through "at-risk" development. However, the same result could be achieved, with less cost and more speed, through conversion.

An example might be helpful. Under current law, if a non-certificated gathering line accepts gas from the interstate system, the gathering line would be "engaged in transportation in interstate commerce," and thus subject to NGA regulation. Now assume that some gathering facilities lie between two interstate pipelines. By electing "at-risk" status, the former gathering lines can now move gas between the interstate pipes, resulting in increased throughput and another transportation alternative.

Obviously some gathering facilities are already fully utilized, and these most likely would not be converted. NGSA, however, believes that there are substantial gathering facilities which could and would be converted to interstate use if the option were available. As an environmentally benign means of expanding the interstate pipeline network, NGSA recommends that the conversion option be given serious consideration.

Any Person May Build or Operate an "At-Risk" Facility

NGSA is firmly convinced that every person should have an equal opportunity to build and operate "at-risk" facilities. A market approach to "at-risk" development will produce more (and more efficient) projects, but only if every producer, marketer and other entrepreneur is left free to supply the "at-risk" market. Conversely, any restrictions would necessarily block entrepreneurs from building facilities at their own risk -- a result clearly contrary to expanding the gas pipeline system.

In keeping the "at-risk" market open to all, legislation must guard against both legal and economic restrictions. For example, with respect to operating certificates, Title X of S. 341 states that "the natural gas company shall accept the certificate." NGSA recognizes that some owners of "at-risk" pipelines will be certificate holders under Section 7 of the Natural Gas Act with respect to other pipelines, and that no "at-risk" pipelines will be exempt from the Outer Continental Shelf Lands Act. However, to the extent Title X suggests that participation in the "at-risk" market should be limited to existing "natural gas companies," i.e., incumbent interstate pipelines, NGSA strongly dissents.

Any statutory definitions must be clearly worded to avoid limiting "at-risk" opportunities to existing "natural gas companies." There is also a question of how to classify "at-risk" developers under the Natural Gas Act. As will be discussed below, "at-risk" development is fundamentally incompatible with many of the regulatory burdens imposed on "natural gas companies" under the NGA. Any definition of "at-risk" developers would therefore need to identify which NGA sections did and did not apply.

Whatever definitional scheme is used, it must be clear that NGA jurisdiction does not extend further than necessary. Therefore, even if "at-risk" developers were to be classified as "natural gas companies" for limited NGA purposes, such status should not be extended to (1) persons, partnerships or corporations which own or are affiliated with an "at-risk" pipeline, or (2) "at-risk" pipeline customers who broker or rebroker their transportation rights. The "at-risk" pipeline itself is a sufficient vehicle for regulatory oversight, and NGA regulation need not be extended to these other entities.

The primary economic barrier to becoming an "at-risk" developer is the monopoly power of the incumbent interstate pipelines. As discussed below, the primary tool for removing this economic barrier is mandatory interconnection.

Mandatory Interconnection

In many cases, an entrepreneur's ability to build an "at-risk" project will depend on access to the established interstate system. A brief example illustrates this point. Assume that natural gas producers discover new supplies which are not presently connected to any interstate pipeline. There are two ways for pipeline service to reach the discoveries. The producers or a third party entrepreneur could build an "at-risk" facility, or the incumbent pipeline could add an extension.

Assuming that some interstate transportation is necessary to bring the newly found gas to market, the two construction alternatives are competitive with each other only if there is some assurance that the "at-risk" facility will be interconnected with the incumbent pipeline. Otherwise, the incumbent pipeline can refuse to interconnect, effectively tying access to the interstate grid (and the market) by allowing only the pipeline to build the necessary extension. (There are at least two variations on this theme: the incumbent pipeline might allow the "at-risk" facility to go forward, but then exact a monopoly rent for the interconnection; or the incumbent pipeline might attempt to exact a monopolistic price for transporting gas from or to the interconnection.) A pipeline might also refuse to interconnect to preserve its hold on markets at other points on its system.

Mandatory interconnection restores the competitive balance. NGSA advocates an amendment to Section 7 of the Natural Gas Act providing that no holder of a Section 7(c) certificate or operator of an "at-risk" facility shall refuse to interconnect with an "at-risk" pipeline if the person seeking interconnection is willing to pay the reasonable cost of the interconnection. The amendment would further require certificate holders and "at-risk" facility operators to receive, transport and deliver gas delivered from or to an "at-risk" pipeline.

A certificate holder or "at-risk" operator would be entitled to insist that a requested interconnection occur at an alternative site, where physically or operationally necessary for receipt or delivery of the gas, provided the alternative was physically, operationally and economically feasible for the new "at-risk" facility. Siting disputes would be resolved by the Commission. In a similar vein, a certificate holder or "at-risk" operator would not be required to expand its system's physical capacity in order to accommodate transportation to or from the interconnection.

In addition, no order directing the receipt, transportation or delivery of interconnection gas should divest any existing shippers' contractual rights as embodied in an authorized service agreement with the incumbent pipeline. Rates for these transportation services would be determined in accordance with the "just and reasonable" standard or the "mutually agreeable" standard described below, depending whether the transportation is occurring on a traditional cost-of-service pipeline or an "at-risk" pipeline.

The "Mutually Agreeable" Rate Standard.

NGSA is confident that more (and more efficient) pipelines will be built if developers and shippers are allowed to allocate project benefits and burdens through private contracts. Given this entrepreneurial setting, "at-risk" rates should not be subject to the "just and reasonable" standard in the Natural Gas Act or the "fair and equitable" standard in the Natural Gas Policy Act. Over the years these two standards have become freighted with cost-of-service connotations, and cost-of-service regulation undermines private contracting. For example, cost-of-service regulation hampers initiative by imposing significant regulatory costs. (In fact, the only "at-risk" developers who would not be harmed by the imposition of regulatory costs are the interstate pipelines -- since they are already cost-of-service regulated.) Moreover, the imposition of cost-of-service regulation would deprive the "at-risk" entrepreneur of whatever benefits might accrue from its negotiated service contracts.

The appropriate measure is whether an "at-risk" rate is "mutually agreeable." The mutually agreeable rate standard serves two functions, affirming negotiated rates and providing a standard for resolving impasse. The affirmation function cannot be overemphasized. All negotiated rates meet the mutually agreeable standard, and should not be subject to any regulatory oversight, particularly under Sections 4 and 5 of the Natural Gas Act.

NGSA strongly believes that negotiation should be the primary mechanism for establishing rates and terms of service. At the same time, NGSA realizes that there may be times when a potential shipper and the operator of an "at-risk" facility fail to come to terms. A potential shipper should be entitled to file a complaint with the FERC alleging that the operator has engaged in conduct which in effect constitutes a denial of service. For example, a complaint could allege that the operator has refused to negotiate, or that the offered price or terms were prohibitively onerous.

Title X does not establish a mutually agreeable rate standard, and instead strongly suggests that facilities constructed under the Title's optional, streamlined procedures will be subject to cost-of-service regulation. As NGSA pointed out above, cost-of-service regulation is fundamentally at odds with "at-risk" development.

Resolving complaints utilizing the mutually agreeable standard in an impasse case, is analogous to resolving civil complaints alleging a violation of the essential facilities doctrine of antitrust law. In an essential facilities case, the defendant is entitled to raise any bona fide business justification for withholding access, including the availability of competitive alternatives. While the plaintiff's cost of duplicating the essential facilities is relevant, the defendant's cost of providing service is not. Similarly, in adjudicating an access impasse, the potential customer's cost of replicating the "at-risk" facility (through by-pass or otherwise) may be considered, but the "at-risk" pipeline's cost of service may not.

Although the "at-risk" pipeline's cost of service would not be at issue, a range of other facts might be introduced. The filed transportation contracts could be relevant. On the other hand, direct comparisons might be inappropriate for a number of legitimate reasons. For example, the subscribing customers may have been willing to share a greater portion of project risks, or the subscribing customers may be receiving a distinct type of service. Rather than attempting to list all the potential grounds for bringing an impasse complaint (and all the potential business justifications for a particular pipeline operator's actions) legislation should establish a prompt means of resolution (e.g., binding arbitration) and underscore the immateriality of the "at-risk" pipeline's cost of service.

An impasse case should be resolved based on a rate that the parties would have agreed to in the absence of the "at-risk" pipeline's inappropriate behavior. Obviously, this standard carries a wide degree of latitude, as it must to accommodate the variety of impasse cases that might arise. But the emphasis rests on what should not be considered -- the "at-risk" pipeline's cost of service (or, similarly, the pipeline's projected units of service).

One final word on impasse remedies is important. An impasse dispute is a conflict between the "at-risk" pipeline and a potential customer. The dispute does not involve existing customers, and their rights should not be affected by a potential shipper's complaint. Therefore, legislation should provide that no remedy in an impasse case may divest any existing shippers contractual rights as embodied in an executed service agreement with the "at-risk" pipeline.

Development Options for "At-Risk" Construction.

NGSA advocates establishing two procedural options for "at-risk" development. Under the pre-construction certificate option, the developer would obtain authorization to construct and operate the "at-risk" facility in accordance with specific statutory standards. Under the non-certificate option, the project would receive neither a construction certificate nor an operating certificate, but the project would be subject to Commission regulations designed to ensure that the project complies with the applicable statutory standards.

1. **Pre-construction Certification Option.** Any person who wants to construct an "at-risk" facility should be permitted to seek a pre-construction certificate under the NGA which would provide for the benefits of eminent domain powers under the NGA and the burden of full review under the National Environmental Policy Act where applicable. NGSA submits that the non-environmental conditions for these certificates should be relatively few, universally applicable and simply stated; moreover, unbridled Commission

authority to insert additional conditions would undermine a market-driven approach to construction. NGSA therefore recommends that the necessary non-environmental conditions be spelled out in the statute, and the Commission be prohibited from imposing new or different conditions.

Although Title X of S. 341 would authorize project construction without certification, a certificate would be required before operations commenced. In issuing the operating certificate the Commission would be authorized to attach "such reasonable terms and conditions as the public convenience and necessity may require."

This proposal is not an adequate substitute for pre-construction certification. An "at-risk" developer's willingness to put pipe in the ground is directly related to his assurance about how the facilities will be able to operate. A liberal operational certification process does not provide that assurance, while pre-construction certification does.

Under pre-construction certification, the "at-risk" developer receives written confirmation that the project will be able to operate as an "at-risk" facility under specified statutory standards, and that no other or further conditions will be imposed. The developer receives this confirmation before construction begins, thus allowing the developer to market its services and obtain financing. NGSA urges adoption of the pre-construction certificate option.

2. **Non-certificate Option**. While some projects may require pre-construction certificates, other projects will not. Developers should therefore have the option to construct and operate "at-risk" facilities without a certificate. By electing non-certificate status, a developer would waive any rights of eminent domain, and there would be no Commission action under NEPA. The applicability of other federal and state environmental laws would not be affected.

Although an operating certificate would not be required, non-certificated facilities must still comply with substantive environmental laws and would still be subject to the non-environmental conditions applicable to the pre-construction certificates. NGSA suggests that legislation direct the Commission to promulgate implementing regulations detailing a method for ensuring that non-certificated facilities meet the same non-environmental conditions that will be imposed on "at-risk" facilities with pre-construction certificates.

Title X does not contain a non-certificate option, and NGSA urges that one be included.

Non-Environmental Conditions Applicable to "At-Risk" Facilities.

Certificate reform should not only speed the expansion of our natural gas pipeline system, but also ensure that the new facilities contribute to the broader, pro-competitive aims of national energy policy. NGSA submits that every "at-risk" facility should be statutorily subject to the following six market-oriented conditions and no other:

1. The facility must be entitled to mandatory interconnection rights;
2. Rates must satisfy a "mutually agreeable" standard;
3. Only transportation service may be offered;
4. Capacity brokering will be pre-authorized;
5. Abandonment of certificated service will be pre-authorized; and
6. Service agreements must be publicly filed.

Mandatory interconnection and the "mutually agreeable" rate standard have already been discussed. The remaining conditions are examined below.

Transportation service only. Over recent years the Commission has repeatedly emphasized the competitive value of keeping a pipeline's transportation service distinct from its "merchant service," i.e., buying gas at one end of the pipe and reselling it at another. Title X of S. 341 reflects this need for separation by limiting construction certificates to facilities providing transportation service. NGSA concurs with this premise and supports a transportation only condition similar to that currently imposed on facilities constructed under Section 311 of the NGPA.

Capacity brokering authority. All shippers on "at-risk" facilities should be categorically authorized to resell or broker their transportation rights on the "at-risk" facility. This will allow existing shippers to transfer their rights in response to market demands, and the resale alternative will give potential customers a second set of capacity sellers. The Commission has ruled that the resale of transportation rights is a jurisdictional transportation service which requires a separate NGA certificate. Without commenting on the Commission's ruling, NGSA submits that the issue can be resolved at the outset by building these resale rights into the statute authorizing "at-risk" construction.

Categorical, exemption from Section 7(b) of the NGA. The duration of service on an "at-risk" facility is defined by the shipper's negotiated service agreement. Accordingly, for all service through an "at-risk" facility, those services should be abandoned automatically at the end of the service agreement. These services should therefore be categorically exempt from the abandonment provisions of Section 7(b) of the Natural Gas Act.

Public filing of transportation agreements. Holders of "at-risk" certificates should be required to file all transportation agreements with the Commission, where those agreements would be kept in open public files. This public filing requirement will serve as a check against anti-competitive behavior, and the contracts will supply a reference point for gauging claims that an "at-risk" pipeline is demanding a transportation rate which violates the "mutually agreeable" rate standard.

NGSA consequently supports the filing proposal in Title X, with two modifications. Title X states that a transportation service agreement satisfies the filing requirement, "provided that such agreement is inclusive of all data and information required to be set forth in a rate schedule." To the extent this requirement ensures that the filed agreements are complete, this proviso is appropriate. However, the reference to "all data" must be expressly limited to exclude the data associated with cost-of-service rate regulation under NGA Sections 4 and 5. The "at-risk" approach to stimulating pipeline construction hinges on exempting "at-risk" facilities from cost-of-service regulation, and a contrary data requirement undermines this approach.

Title X also proposes that the agreements be filed "prior to initiating transportation service." It may be that a claim of exclusionary pricing will arise before an "at-risk" facility goes into service, and NGSA therefore suggests that the filing deadline should be 60 days before the commencement of service.

Procedures Applicable to Pre-Construction Certificates.

Much of the delays attendant to traditional certification proceedings stems from the intervention of entities who see a competitive advantage in forestalling a new project. This is particularly true when it is perceived that a particular supply or market can support only one pipeline. In those cases, one applicant's administrative delay is seen as a competing applicant's victory.

Since all of the non-environmental issues will be resolved by the statutory definition, a pre-construction certificate proceeding should be limited to environmental evaluation under NEPA. Standing to intervene in these proceedings should therefore be limited to parties raising environmental issues, and the Commission should be instructed to deny intervenor status to those who would enter a proceeding simply to gain a competitive advantage over an "at-risk" applicant. By limiting intervention rights, legislation can reduce unwarranted delays in the pre-construction certificate process, while focusing the Commission's resources on environmental issues.

Procedures applicable to Mandatory Interconnection and Impasse Complaints.

Mandatory interconnection and impasse complaints could be handled in a variety of procedural settings, provided that a premium is placed on expeditious resolution. The FERC should be required to consider the use of binding arbitration or mediation outside the Commission as a means of complaint resolution. Alternatively, there are a number of expediting procedures which could be used within the Commission, including the use of "paper hearings" where the dispute would be resolved on the basis of written pleadings without hearing testimony. In any event, full adjudicatory hearings should be reserved for the few cases where clearly required by the interests of justice.

NEPA Compliance.

NGSA supports the NEPA compliance provisions of Title X. By permitting the Commission to serve as the lead agency in certificate matters, and by permitting environmental documents to be prepared by approved contractors, Section 10003 will expedite the environmental review of both "at-risk" and traditional projects. As an advocate of "at-risk" construction and economically efficient traditional construction, NGSA applauds these measures to speed environmental review.

Replacement and Minor Expansion of Facilities Certificated Under Section 7.

While an express advocate of "at-risk" construction, NGSA recognizes that there is also benefit in streamlining procedures for certificating traditional facilities. In comments responding to the Commission's proposed rule on construction certification, NGSA advocated that any replacement or expansion of traditional facilities costing less than $50 million should be automatically certificated if no protests are filed within 45 days after the Federal Register publishes notice of the certificate application.

NGSA's proposed rule does not distinguish between new and replacement facilities, nor would it exempt any facilities from existing certificate requirements. It would, however, streamline certificate procedures for relatively low cost facilities. This rule is premised on a clear understanding that certification of a facility under Section 7 does not imply that the costs of those facilities have been judged prudent and recoupable in a rate case under Section 4.

Rate Base Treatment of "At-Risk" Facilities.

Title X provides that when traditional and non-traditional (in NGSA's terms: "at-risk") facilities are owned by the same "natural gas company," separate books should be required. Putting aside its concern about the term "natural gas company," and assuming that the restriction would apply when the various facilities were owned within the same corporate family, NGSA concurs.

NGSA also agrees that in some cases it may be appropriate to integrate "at-risk" facilities into a traditional rate base. The effect of such reclassification on the "at-risk" pipeline's customers would be a matter governed by their service contracts.

NGSA concurs that there should be some limits on the ability to obtain cost-of-service treatment for "at-risk" facilities. As provided in Title X of S. 341, conversions should not be permitted during an "at-risk" facility's first ten years of operation. NGSA would also add an express provision assuring that conversions would not affect the remaining contract rights of subscribing shippers. In addition, when a facility is converted the rate base may not increase by more than the depreciated cost of the converted facilities, and the customers of the traditional pipeline should have the right to protest the conversion.

Section 311 Reform.

NGSA endorses Title X of S. 341 in expanding Section 311 so that qualifying interstate and intrastate transportation can be provided on behalf of any person. The purpose of this provision was to integrate the interstate and intrastate markets, and this aim is ill served by the court's restrictive reading of the current "on behalf of" standard.

NGSA submits that the vast bulk of interstate pipeline construction should proceed either as "at-risk" facilities or as traditional facilities. Widespread use of Section 311 construction authority is unnecessary and inappropriate, particularly if notice-and-protest proceedings are made available for projects costing up to $50 million. NGSA therefore urges that interstate pipeline construction under Section 311 should be limited to those minor facilities which are required to interconnect with other facilities providing Section 311 service.

NGSA also notes that there is a debate over the Commission's authority to impose NEPA requirements on Section 311 projects. This debate would largely be rendered moot if Section 311 construction were limited to incidental facilities.

2. COMMISSION RESTRUCTURING

While sharing a desire to expedite the Commission's disposition of certificate and rate proceedings, NGSA believes that these goals would not be served by merging the Commission into the Department of Energy. First, it is difficult to see how incorporation into DOE would expedite the decisionmaking process.

Second, the restructuring proposal would convert the Commission from an independent regulatory agency to an arm of the executive branch. Because of its five-member structure, the Commission has had to operate by consensus and accommodation. As a result, its policies have often reflected a balance of views. The proposed restructuring could further politicize the decisionmaking process, and remove the current institutional incentive for balanced policymaking. NGSA has not always been pleased with the Commission's pace, but speed should be gained by streamlining the existing structure, not sacrificing the Commission's independence.

3. ADMINISTRATIVE AND JUDICIAL REVIEW OF COMMISSION DECISIONS

Overview.

NGSA supports efforts to shorten the very lengthy period that frequently now occurs between the time an issue is first considered by FERC and the time a final, non-reviewable order is available.

A major portion of this delay is caused by the fact that virtually every Commission order of significance is first revisited on rehearing and then appealed to the federal courts. NGSA views the rehearing process as a valuable opportunity for industry members to point out shortcomings which the Commission should, and may be willing to, correct before an order becomes final. When the Commission does make changes on rehearing, the alterations often reflect facts which industry commentators did not properly communicate when the Commission first considered the order. This type of correction is infinitely preferable to the extended process of court review and remand to the Commission.

Similarly, NGSA does not support a limitation on court review of Commission orders. Judicial review provides a valuable check on agency abuse or significant error.

While NGSA does not seek to compromise anyone's right to seek rehearing or judicial review, anything which can be done to speed these proceedings would be helpful. In some significant cases the wait for a final order has lasted several years, and during this interim it is difficult, if not impossible, for producers or other industry members to plan and conduct their business. This is especially true with regard to business decisions which require long range planning and heavy investment of capital. NGSA therefore supports the efforts in Title X to reduce these delays.

Rehearing Deadlines.

On rare occasions, the Commission has issued a tolling order on rehearing and then not acted finally for many months or even years, effectively denying judicial review. This infrequent but significant problem should be addressed. On the other hand, if the time period for rehearing is shortened too much, the Commission may be discouraged from undertaking any serious rehearing effort, with the unfortunate result that the Commission would simply tend to rely on its initial orders and the initial investigation and fact finding which supported them.

Accordingly, NGSA supports a fixed limitation on extensions of time for Commission action on rehearing. The present Senate proposal for a one-time 60 day extension appears shorter than is necessary to achieve the desired goals, and NGSA would recommend a one-time extension for up to 120 days.

Furthermore, Title X proposes to limit this extension to cases of "extraordinary cause." NGSA sees no necessity for this limitation. NGSA is confident that the Commission will use such extension powers only where necessary, and NGSA wishes to avoid the possibility of separate appeals on the issue of whether the extension was in fact for "extraordinary cause."

Timing and Substance of Petitions for Review.

For the reasons discussed above, NGSA would support a limitation on the time for filing a petition for review with the federal courts. However, dropping the time from 60 days to 30 days (as the Senate bill does) may not leave enough time to fully review what are sometimes very lengthy and complex Commission orders. NGSA would support shortening the time frame from 60 to 45 days for filing a petition for review.

Title X of S. 341 would require parties to specify the ground or grounds for requesting judicial review of a Commission order. NGSA opposes this potentially burdensome provision because it will not speed court review. The parties are generally fully informed of each other's positions based on their requests for rehearing. Moreover, many reviewing courts already require parties to file statements of issues or similar pleadings as part of their docket management procedures. Finally, a specificity requirement could impose significant burdens given existing venue statutes which places a premium on filing petitions within 10 days after the Commission issues its order.

Exclusive Court Jurisdiction to Review Commission Orders.

Section 19(b) of the NGA and Section 506(a)(4) of the NGPA provide that once a Commission order and the underlying record are lodged in reviewing court, that court has exclusive jurisdiction to "affirm , modify or set aside" the order. Thus, if the Commission desires to reconsider an otherwise final order which is under review, it must petition the reviewing court to remand the record, and the court is under no obligation to do so.

Title X of S. 341 proposes to delete the provisions of the NGA and NGPA which provide for exclusive court jurisdiction. While on occasion this system may delay correction of a defective order, NGSA is concerned about the administrative uncertainty that may occur if the Commission is issuing rewritten orders at the same time courts are reviewing the original ones. The purpose of legislation in this area should be to increase certainty and the speed with which that is achieved, not increase uncertainty. For this reason, NGSA feels that it is important that it be clear precisely in what forum an issue is being considered at any one time. Thus, we do not support eliminating the courts' exclusive jurisdiction to review FERC orders when the record has been filed with the court.

Notice Periods for Rate Changes.

NGSA supports lengthening the notice period so that rate increases cannot become effective until they have been on public file for 60 days. However, the reason for this extension -- to give the Commission and pipeline customers more time to consider whether a filed rate increase is just and reasonable -- applies only to increases. If a rate filing calls for a decrease, there is no reason to extend the time for it to go into effect. Indeed, it would seem appropriate for a rate reduction to go into effect immediately, even though later review may suggest that even lower rates should be placed into effect. Accordingly, NGSA supports a 60-day notice period for rate increases, and a one-day notice period for rate decreases.

Refund Obligations and Mandatory Periodic Rate Filings

Under Title X, the Commission would be authorized to impose refund obligations as of the date a pipeline files for any rate change, whether an increase or decrease. This is a change from the present statute, which arguably permits refunds only for rate increase filings.

NGSA agrees that potential refunds should accrue from the date of a rate filing, and that this refund obligation should extend down to whatever new level the Commission finds to be just and reasonable, regardless of what the previous rate approved by the Commission was. NGSA is concerned, however, that the present proposal would discourage pipelines from filing for rate decreases, since such a filing would expose a pipeline to unlimited rate reductions and retroactive refunds.

NGSA therefore recommends that pipelines be required to file new rate cases at some reasonably regular period, such as three years. Refunds should be available effective to the date of the required filing. These refunds should return all amounts collected in excess of that authorized under rates finally judged by the Commission to be just and reasonable -- even if those approved rates are lower than previously approved rates, or the rates filed for by the pipeline.

The Commission's Rulemaking Authority.

NGSA has always believed that the Commission possesses adequate power under the Natural Gas Act to establish rates and charges, or to issue certificates of convenience and necessity or to abandon any facilities or services, by rulemaking. It further believes that the recent opinion of the United States Supreme Court in Mobil Oil Exploration and Producing Southeast, Inc., et al v United Distribution Companies, et al confirms this. NGSA believes this is a sound and necessary approach to the Commission's responsibilities and would not oppose the Senate bill proposal.

We would only express a small concern that the legislative proposal could be seen as a suggestion that the Commission's rulemaking authority in this area is inadequate. To the extent the proposal is an expression of the sentiments expressed in the Mobil case, NGSA shares this sentiment and recommends that a conference report or floor debate clarify that Congress is merely explicitly confirming what it believes to be the current state of the law, as interpreted by the Supreme Court. If, on the other hand, this proposal is intended as a procedural device to expand the Commission's substantive authority, NGSA submits that extensive study is warranted before any definitive action.

4. VEHICULAR NATURAL GAS

NGSA strongly opposes any reservation of state regulatory authority to impose price or other economic regulation on the sale of vehicular natural gas (VNG). Instead, NGSA recommends that legislation declare VNG sales shall be unregulated, and that the states are pre-empted from imposing any form of economic regulation.

State regulation of VNG sales will impede the use of VNG, a result directly contrary to the goal of encouraging domestic gas use as a substitute for imported oil. Regulation of VNG prices by state public utility commissions will lead to the same types of inefficiencies and distortions that previously existed in the interstate gas markets. In addition, state regulations will inevitably vary across the map, making it more burdensome for potential sellers of VNG to operate in a nationwide market. Finally, some states are likely to establish substantial barriers to entry in the VNG sales business. For example, a seller of VNG in some States may need to qualify as a "public utility." Such high barriers to entry will restrict competition in VNG markets and contribute to the creation of monopoly power. In short, the best way to ensure that consumers can purchase VNG at the lowest possible price is through a competitive market, and NGSA supports efforts to promote and maintain that market free of regulatory intervention.

5. PIPELINE SALES DEREGULATION

NGSA opposes the immediate statutory deregulation of both sales and transportation services as set forth in S. 570. NGSA believes that for the foreseeable future most interstate pipelines will continue to possess both monopoly and monopsony power, and that continued FERC oversight is appropriate and necessary. Unlike the "at-risk" pipelines that would be built under the proposed legislation, most existing interstate pipelines were built on an exclusionary basis (i.e., a monopoly) conditioned upon utility-style regulation as provided under the Natural Gas Act. The quid pro quo behind this regulatory "pact" remains to this day and should not be swept aside by deregulation. This does not mean that a lighter handed regulation of the pipelines' services is not appropriate in some circumstances.

In the case of pipeline sales, NGSA has supported negotiated rates where the pipeline has achieved comparability of service on its system. Comparability, however, is a very complex issue on which the Commission is developing policy and guidelines. Other inter-related issues, such as the pipeline's service obligation to its customers and customer conversion rights, also remain unresolved on many pipelines. Moreover, in some situations purely negotiated rates may be appropriate for some but not all of the pipeline's customers. In sum, the degree of regulation of the pipelines' sales service remains subject to many interrelated issues which are best resolved through the existing regulatory process and not through legislation.

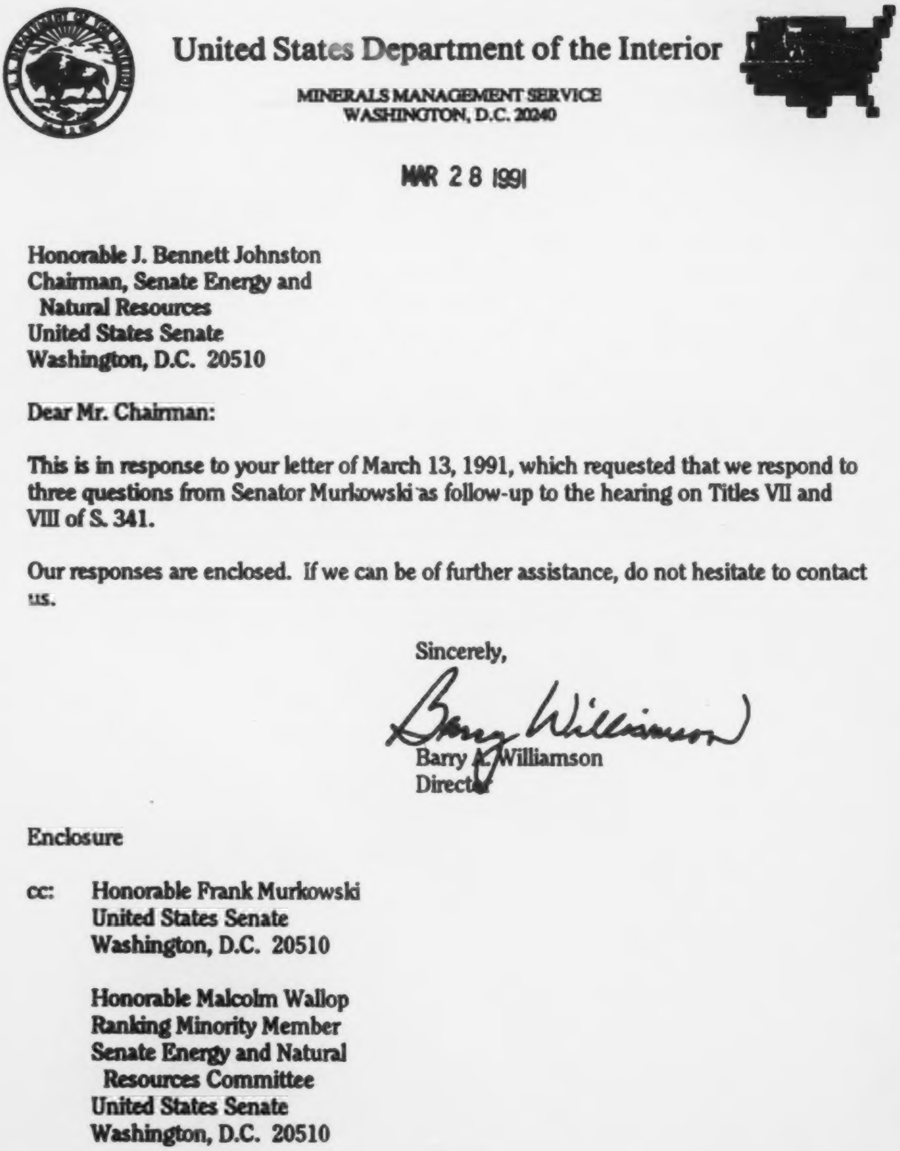
As to the existing pipelines transportation services, NGSA opposes any form of blanket deregulation at this time. On nearly all existing interstate pipelines, monopoly power over the transportation service still exists. Even in markets served by more than one pipeline, the market is simply allocated among or between the pipelines. Market allocation does not equate with market competition.

This is not to say that rates on existing interstate pipelines for all services must always be cost-based. However, there still is a need for regulatory oversight of such rates to assure that they are "just and reasonable" and that the market power of the pipeline over its transportation services is not wielded in a discriminatory manner. NGSA, through its White Paper on Pipeline Rate Reform, has suggested numerous ways for developing more competitive and market-responsive transportation rates and services. However, as was the case with the pipeline sales service, this is a matter that is much better resolved by the existing regulatory process rather than legislation.

APPENDIXES TO MARCH 11, 1991 HEARING

(Titles VII and VIII)

Appendix I—Responses to Additional Questions



United States Department of the Interior
MINERALS MANAGEMENT SERVICE
WASHINGTON, D.C. 20240

MAR 28 1991

Honorable J. Bennett Johnston
Chairman, Senate Energy and
Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

This is in response to your letter of March 13, 1991, which requested that we respond to three questions from Senator Murkowski as follow-up to the hearing on Titles VII and VIII of S. 341.

Our responses are enclosed. If we can be of further assistance, do not hesitate to contact us.

Sincerely,

Barry Williamson

Barry A. Williamson
Director

Enclosure

cc: Honorable Frank Murkowski
United States Senate
Washington, D.C. 20510

Honorable Malcolm Wallop
Ranking Minority Member
Senate Energy and Natural
Resources Committee
United States Senate
Washington, D.C. 20510

Followup Questions to Hearing on Title VIII, S.341

1. The MMS has proposed 8 lease sales in the Alaska OCS. Could you comment on the importance of the proposed lease sale areas in terms of potential production?

Response: MMS estimates that undiscovered oil resources on the Outer Continental Shelf (OCS) amount to between 3.6 and 24 billion barrels of oil. The Alaska OCS contains between an estimated 2.5 and 8.7 billion barrels of undiscovered oil resources. Within the eight Alaska OCS planning areas, the tracts under consideration for leasing in the Comprehensive Program for 1992-1997 contain between an estimated 1.7 and 3.1 billion barrels of undiscovered oil resources.

The above are conditional estimates and represent the possible range of resources present, given the assumption that hydrocarbons exist in the area of study. Gas on the Alaska OCS is assumed to be uneconomic at the present time.

2. Could you please comment on the oil potential and national significance of leasing and possible developments of the Chukchi and Beaufort Sea lease sale areas?

Response: These are currently viewed as the two most promising offshore areas in Alaska. Conditional mean estimates of undiscovered, economically recoverable resources in the Chukchi and Beaufort Sea planning areas are 5.96 and 1.66 billion barrels of oil, respectively. Conditional estimates are based on the assumption that hydrocarbons exist in planning areas. There may be a substantial range around the mean. These areas hold the potential for some of the largest new oil discoveries predicted anywhere in the United States. For example, the conditional mean estimate for Chukchi Sea oil resources is even larger than the estimates for the Arctic National Wildlife Refuge (ANWR) coastal plain, though the probability of a commercial discovery is lower.

Previous lease sales have already taken place in the Chukchi and Beaufort Seas. Only a small percentage of these areas have been leased, and many of these leases will soon expire. These two planning areas are of particular interest due to their resource potential. In the Comprehensive Program for 1992-1997, lease sales will be considered for the Chukchi Sea planning area in 1994 and 1997 and for the Beaufort Sea planning area in 1993 and 1996.

3. These Alaska OCS areas are nationally important, however, local communities bear the burden of supporting the OCS development and associated impacts. How would impact aid programs from OCS revenues benefit local communities?

Response: President Bush, in his June 26, 1990, statement on offshore leasing and development, directed the Department of the Interior to prepare a legislative initiative that will provide coastal communities directly affected by OCS development with a greater share of the financial benefits of new development and with a larger voice in decision making. The proposal being considered by the Administration would provide impact assistance to local communities in a manner that is proportional to impacts associated with OCS development. We believe it is appropriate to provide communities located near OCS development with a greater share of the benefits derived from such development.

Department of Energy
Washington, DC 20585

April 12, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 11, 1991, Robert H. Gentile, Assistant Secretary for Fossil Energy, testified before your committee on Titles VII and VIII of S. 341.

Following the hearing, you submitted written questions on behalf of Senators Wallop and Akaka to supplement the record. Enclosed are the answers to questions 1, 3, 4a, 4b, 4c, 5a, 5b, 5c, 7a, 7c, and 8, (Wallop), and answers to questions 1, 2, 3, 4, 5, 6, 7, 10, 11, 12, and 15 (Akaka). The remaining answers are in the clearing process and will be forwarded to you as expeditiously as possible.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Renee Wilhite, (202) 586-4277.

Sincerely,

Joseph C. Karpinski - for

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

QUESTIONS FROM SENATOR WALLOP

Question 1: Would you agree that many of today's energy problems stem from reliance on an international market-place where energy prices have no relationship to the costs of production or the full costs of maintaining access to those supplies?

Answer: We agree that in the international oil market, prices are not directly tied to the costs of production or to the full costs of maintaining access to supplies. Oil prices are affected by OPEC actions and by other political and governmental influences. However, we do not believe it is accurate to say that today's energy prices have no relationship to the costs of production or the costs of maintaining access to suppliers. Over the long term, the basic laws of supply and demand do operate in the world oil market. For example, during the mid-1980s world oil prices fell sharply in spite of OPEC's efforts to maintain higher price levels through production quotas. The quotas were rendered ineffective, in large part, by higher oil production from non-OPEC countries resulting from the sharp increases in oil prices during the 1970s.

As the National Energy Strategy points out, we are part of an interdependent, international world oil market. We cannot change that reality. We can, however, reduce our vulnerability to disruptions in the world market by the demand, supply and contingency preparedness measures set forth in the NES.

Question 3. As you are aware, S. 341 contains a provision which would establish a price differential between domestic and imported crude oil and petroleum products. This is accomplished by requiring that approximately 9 percent of crude oil and petroleum product imports, or the equivalent, be furnished to the Federal government for use in both filling the Strategic Petroleum Reserve and meeting the fuel requirements of the Department of Defense. Would you agree that this requirement is in effect a surcharge on the importation of crude oil and petroleum products?

Answer: We agree that this requirement is in effect a charge on the importation of crude oil and petroleum products.

QUESTION FROM MALCOLM WALLOP

Question 4:	Would you comment on the effectiveness of the recent coordinated IEA drawdown of strategic stocks.
	a. In your judgment, was there full cooperation among IEA members?
Answer:	There has been excellent cooperation among IEA members in planning their individual country responses to the IEA Contingency Plan. OECD countries committed to make available to the market a total 2.5 million barrels per day (MMBD), of which 2 million barrels per day were from strategic (1.5 MMBD) and commercial (.5 MMBD) stocks. Individual member commitments were implemented flexibly. Actual results are being evaluated by the IEA. We will provide the IEA evaluation of the Contingency Plan when it is available.
	b. What was the estimated effect on international energy prices?
Answer:	We do not believe that it is possible to quantify the effects on international energy prices of the coordinated response; but, we believe the stability in oil prices was due, in part, to the successful development and implementation of an IEA coordinated response.
	c. Is the coordinated drawdown still in effect? Is the United States still drawing down the SPR?
Answer:	Although the coordinated response plan was officially deactivated on March 6 by the IEA Governing Board, implementation continued through the end of March by the United States and other IEA countries.

QUESTIONS FROM SENATOR WALLOP

Question 5a: What are the Department's plans for use of the funds received from the recent drawdown of the SPR?

Answer: The Department plans to use the funds received from the recent drawdown of the SPR to acquire oil to fill the SPR. Our initial approach will be to pursue attractive acquisition contracts with foreign producers, including use of new authorities granted in Public Law 101-383.

Question 5b: When does the Department intend to begin expending these funds for replacement of the crude oil drawn down?

Answer: The Department intends to resume filling the SPR as soon as possible, following exploration of attractive alternatives to direct purchase. The budget, which was prepared before the recent drawdown, assumed resumption of fill in mid-FY 1992, but this timing will be reviewed in the context of progress made in negotiating an acquisition approach.

Question 5c: Are you considering the leasing of crude oil, rather than the purchase of the replacement crude oil?

Answer: We are considering a number of acquisition methods, including "leasing," rather than relying exclusively on conventional direct purchases. Our budget assumes a "lease" approach.

QUESTION FROM MALCOLM WALLOP

Question 7a.	When does the Department intend to implement last years' authority? What is your time table for the negotiation of a leasing agreement?
Answer:	The Department intends to pursue alternative financing as soon as overall coordination of the negotiating team can be arranged between DOE and other elements of the Executive Branch. Because we are still a military presence in the Middle East and have ongoing contact with the nations in that region, our objectives for SPR fill must be considered in the larger context of relations with those countries. As a result, the timing of negotiations will be affected by the interagency consultations now under way.

QUESTIONS FROM SENATOR WALLOP

Question 7c: Has the Office of Management and Budget placed any time restrictions on the Department regarding the expenditure of currently available funds for the leasing of oil?

Answer: The Office of Management and Budget has made available all appropriated funds for obligation.

QUESTION FROM MALCOLM WALLOP

Question 8: When you enter into oil "leasing", would the Department consider a leasing arrangement that included an up front payment to the producer for crude oil to be delivered in the future at the maximum SPR fill rate?

Answer: We are open to consideration of a variety of possibilities. We would analyze alternatives presented using the principles described in the SPR Alternative Financing Study including those set forth in OMB Circular A-104.

QUESTIONS FROM SENATOR AKAKA

Question 1. Mr. Gentile, identify the extent to which Hawaii has relied on petroleum products to satisfy its total energy needs.

Answer: Hawaii relies on petroleum to meet about 98 percent of state energy consumption, compared to the national average of 24 percent. The other 2 percent of Hawaiian energy consumed consists of coal, natural gas, nuclear energy, hydro-electric and geothermal energy.

Question 2. Mr. Gentile, identify the percentage of foreign oil imported to Hawaii in each of the past three years.

Answer: Hawaii imported 52 percent of the crude oil supplied to its refineries in 1988, 61 percent in 1989, and 60 percent in 1990.

QUESTIONS FROM SENATOR AKAKA

Question 3: Mr. Gentile, estimate the percentage of foreign oil that Hawaii will import in each of the following years: 1990, 1995, 2000, 2005, 2010.

Answer: The Energy Information Administration (EIA) makes projections of United States' energy supply and consumption through the year 2010. EIA does not project energy data for individual states. Below are U.S. national base case projections of net oil imports (excluding imports for the Strategic Petroleum Reserve) as a percent of oil consumption. These projections are published in EIA's Annual Energy Outlook (1990).

	Percent Dependence of the U.S. on Net Oil Imports
1990	42
1995	50
2000	53
2005	57
2010	61

Hawaii's dependence on foreign oil in the 1988 through 1990 period is estimated to have been slightly over 60 percent of its total oil requirement. Though EIA does not have any official projections for Hawaii, it is not expected that its dependence on foreign oil will grow at the rate of projected national dependence (above). Hawaii's location is favorable for shipments of Alaskan crude oil and its two refineries have been adapted to process Alaskan oil. We would expect that Hawaii would continue to use their current refinery configurations and transportation cost advantages for processing Alaskan oil in the future.

QUESTION FROM SENATOR AKAKA

Question 4: Mr. Gentile, requirements that only double-hulled tankers may service American ports were recently enacted. Estimate the decline in the number of: 1) U.S. flag tankers, and 2) foreign flag tankers that will be available to serve U.S. ports for each of the following years: 1990, 1995, 2000, 2005, 2010.

Answer: The Department of Transportation collects the data and performs the analysis necessary to respond to this question. We defer this question to them.

Question 5: Mr. Gentile, what is the overall U.S. emergency requirement for tankers (in deadweight tons) and what percentage does this figure represent of the total world tanker fleet?

Answer: The Department of Transportation collects the data and performs the analysis necessary to respond to this question. We defer this question to them.

QUESTIONS SUBMITTED BY SENATOR AKAKA

Question 6 : **Mr. Gentile, given the limitations of domestic refinery terminals, SPR loading docks, storage capacity, and the Panama Canal, identify the size limitations which must be considered in assembling a U.S. emergency tanker fleet to serve the U.S. in the event of an oil emergency.**

Answer : **The restricting drafts at domestic refinery terminals (excluding Hawaii and the Louisiana Offshore Oil Port), which have historically imported crude oil and would be likely recipients of SPR crude, vary from 12 to 46 feet. At some ports, length and beam restrictions also apply, but draft is the prevailing limitation. Drafts at the terminals providing SPR outloading capability range from 36 to 40 feet. The published draft of the Panama Canal is 39.5 feet. Storage capacity varies with concurrent commercial activity. Limited storage capacity available at receiving terminals could restrict the size of cargoes that could be accommodated and degrade the overall efficiency of cargo transfer operations. Considering the above limitations, the vessel sizes needed to support an SPR drawdown range from 20,000-barrel barges to 500,000-barrel tankers.**

Question 7: Mr. Gentile, what percentage of the total 1) U.S., and 2) foreign flag tanker fleet satisfies the size requirements identified above?

Answer: The Department of Transportation collects the data and performs the analysis necessary to respond to this question. We defer this question to them.

QUESTIONS FROM SENATOR AKAKA

Foreign Oil Dependency by Pacific Basin Nations

Question 10: Mr. Gentile, identify the estimated dependence on foreign oil by Pacific Basin nations for each of the following years: 1990, 1995, 2000, 2005, 2010.

Answer: For the purpose of this analysis, the Pacific Basin is defined to include Japan and the Newly Industrialized Countries (NICs) of Asia, namely Hong Kong, Indonesia, Malaysia, the Philippines, Singapore, South Korea, and Taiwan. Of these countries, only Indonesia and Malaysia currently export more oil than they import. All of the other countries listed import almost all of the oil they consume. Consumption levels for this region during 1989 in million barrels per day (MMBD) are listed below.

	Consumption	% of World
NICs	2.8 MMBD	4.2%
Japan	5.0	7.6%
Total World	65.8	100.0%

Significant increases in the amount of oil these countries will consume in the future, with the possible exception of Japan, is forecasted. With significant increases in consumption expected in the future, and very little domestic production available, (again, excepting Indonesia and Malaysia) these countries will probably become increasingly dependent on foreign oil. It is conceivable that even Indonesia and Malaysia could import more oil than they export by the year 2010. However, specific estimates for either the percentage of consumption that is imported, or the level of imports that these countries will probably require between now and the year 2010 are not available.

QUESTION FROM DANIEL AKAKA

Question 11 : Mr. Gentile, based upon the information above, the increased reliance on imports in the Pacific Basin through the year 2000 and 2010 suggests that these regions will not have sufficient indigenous supplies available to facilitate SPR exchanges with Hawaii in the event that Middle East oil movements are suddenly and substantially reduced. Do you agree or disagree with this statement? Explain.

Answer : We do not agree that there will necessarily be insufficient supplies for Hawaii during a future disruption of Middle East oil. The facility of exchanging SPR oil with Hawaiian refiners in the event of a Middle East oil disruption will depend to a large degree on decisions made by the two companies owning refineries in Hawaii, Chevron and Pacific Resources, Inc. Both companies have direct business relations with producing fields in the Pacific Basin, and the future of such relations will affect their access to oil in this region. Both companies bid in the recent SPR sale and one was a successful offeror.

QUESTIONS FROM SENATOR AKAKA

Middle Eastern Oil Dependency by Pacific Basin Nations

Question 12: Mr. Gentile, estimate the extent to which Pacific Basin countries will rely on Middle Eastern oil for each of the following years: 1990, 1995, 2000, 2005, 2010.

Answer: For the purpose of this analysis, the Pacific Basin is defined to include Japan and the Newly Industrialized Countries (NICs) of Asia, namely Hong Kong, Indonesia, Malaysia, the Philippines, Singapore, South Korea, and Taiwan. Currently, only Indonesia and Malaysia export more oil than they import. All of the other countries listed import almost all of the oil they consume. Significant increases in the amount of oil these countries will consume in the future, with the possible exception of Japan, is forecasted. With significant increases in consumption expected in the future, and very little domestic production available, (again, excepting Indonesia and Malaysia) these countries will probably become increasingly dependent on foreign oil. It is conceivable that even Indonesia and Malaysia could import more oil than they export by the year 2010. The majority of these imports are expected to originate from the Middle East. In 1988, the latest year data is available, these countries, excluding Hong Kong, imported roughly two out of every three barrels of crude oil imports from the Middle East. This percentage is expected to rise over the next 20 years. However, specific estimates for the percentage of imports that are imported from the Middle East between now and the year 2010 are not available.

QUESTIONS FROM SENATOR AKAKA

Question 15: In the event that Middle East oil is substantially and suddenly reduced, does the Department of Energy contemplate a scenario in which Hawaii's needs for oil would be met by shipments from the West Coast?

Answer: As mentioned previously, Hawaii's energy situation will be addressed more fully in the Department's comprehensive Hawaiian energy study and will depend to a large degree on business decisions made by Chevron and Pacific Resources, Inc. The Department estimates that certain National Energy Strategy initiatives; if implemented could increase domestic oil production by 1.8 million barrels per day above the level projected for the year 2000. This would include a substantial increase in supplies available to the West Coast.

Department of Energy
Washington, DC 20585

April 17, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 11, 1991, Robert H. Gentile, Assistant Secretary for Fossil Energy, testified before your committee on Titles VII and VIII of S. 341.

Following the hearing, you submitted written questions on behalf of Senators Wallop and Akaka to supplement the record. Enclosed are the answers. The remaining answer to question 3b (Wallop) is still in the clearing process and will be forwarded to you as expeditiously as possible.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Renee Wilhite, (202) 586-4277.

Sincerely,

Jacqualine Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosures

QUESTIONS FROM SENATOR WALLOP

Question 2a: Do you agree that the United States must find the means to stimulate development of competitive supplies by assuring sufficient stability in domestic energy prices that investments can be made in the development of domestic alternatives?

2b: What mechanism would the Administration propose to accomplish this objective?

Answer: Assuring greater stability of domestic energy prices would require direct Federal Government intervention in the domestic energy market, particularly the oil market, for the purpose of controlling prices through some type of mechanism such as a variable import fee. Experience has shown and the Department believes that the energy benefits of such a mechanism would be outweighed by the adverse effects on the U.S. economy.

For example, the analysis conducted in support of the National Energy Strategy (NES) indicates that if a $25 per barrel oil price were maintained through an import fee, it would reduce the Nation's growth, increase inflation and consumer costs, and decrease the competitiveness of U.S. companies in foreign and domestic markets. The present value of the gross national product losses would be approximately $150 billion.

Rather than trying to impose a federal price floor on the oil market, we believe the key to stimulating development of domestic energy supplies is providing incentives and better technology to reduce the cost of U.S. energy production and make it more competitive in world markets. That is why the President proposed oil and gas incentives similar to those enacted by the

Congress in last year's budget reconciliation legislation. That is why the NES supports extension of the business investment tax credit for solar and geothermal energy. And, that is why the NES: (1) expands R&D programs for advanced technologies; (2) promotes transfer of these technologies to the marketplace; and, (3) removes barriers to the more efficient production of alternative fuels.

QUESTION FROM MALCOLM WALLOP

Question 5:	**What issues remain before the Administration can proceed with expansion of the Reserve to one billion barrels?**
Answer :	**Current facilities and capacity for the SPR are limited to 750 million barrels. The Department has recently completed a preliminary study of possible sites for expansion to 1 billion barrels. However, the selection of the specific sites will be affected by the National Environmental Policy Act of 1969 review process and is expected to take two years. In addition, the cost of 250 million barrels of facilities is expected to be approximately $1.9 billion, and to take 7 years to construct.** **As required by statute the Department will present an SPR Plan amendment to the Congress in 1992, which will lay out final recommendations for sites and the approach and schedule for expansion.**

QUESTION FROM MALCOLM WALLOP

Question 6: In your judgment, would the storage by producing countries of large volumes of crude oil in the United States be beneficial from the standpoint of energy security?

Answer: The SPR is designed to inject oil into the market economy in the event of a severe energy supply disruption. Much of the benefit of SPR storage could be achieved, whether the oil was owned by a foreign producer or by a private firm.

Question 7b: The President's FY92 budget request indicates that the Administration does not propose to resume SPR fill until the last half of 1992. When fill is resumed, the proposed fill rate is only 50,000 barrels per day. At that rate it will take over 20 years to complete the task. What is the basis for this delay?

Answer: The SPR has been filled at a rate of approximately 50,000 barrels per day over the last five years. The proposed resumption of fill at a rate of 50,000 barrels per day, included in the Fiscal Year 1992 budget, was based on our progress, as of that time, in seeking attractive acquisition arrangements.

QUESTION FROM SENATOR WALLOP

Question 9: Considering present international oil supply and Federal budget constraints, would the Department reasonably expect to be able to obtain substantially more crude for the SPR at this time compared to an outright purchase?

Answer: The Department has set a policy goal of pursuing alternative financing approaches before use of conventional purchase methods for oil acquisition. We believe that a number of financing options have considerable promise and could result in a more cost-effective fill of the Reserve.

QUESTIONS SUBMITTED BY SENATOR AKAKA

Question 8 : Mr. Gentile, what are the problems associated with assembling a tanker fleet on short notice to serve the U.S. in the event of a major oil supply disruption?

Answer: The availability of sufficient tankers to support an SPR drawdown is a function of the oil supply disruption scenario in terms of time of year, military requirements, size of disruption, lost source(s) of supply, etc. The principal difficulty associated with obtaining sufficient suitably sized tankers is the "Jones Act" requirement to use only U.S.-flag tankers in transporting oil between U.S. ports. These vessels are normally fully employed in the Alaskan crude, foreign and coast-wise trades, or are under charter to the military; thus, their availability depends on the extent this normal business is curtailed at the time of an oil supply disruption. This problem can be avoided with respect to an SPR drawdown, however, by the Secretary of the Treasury's granting a general waiver to the requirement, and allowing the participation of more readily available foreign-flag tankers, as was done during the recent SPR drawdown.

QUESTION FROM DANIEL AKAKA

Question 9: Mr. Gentile, identify the estimated dependence on foreign oil in the Petroleum Administration for Defense District V (PADD V) for each of the following years: 1990, 1995, 2000, 2005, 2010.

Answer: Although the Department has made projections of levels of imports for the whole of the United States, none of the major studies which we have published are supported by projections of imports broken down by PADD. However, for purposes of the SPR expansion study, forwarded to Congress on April 4, 1991, and working from Energy Information Administration projections of imports for the whole country, the Office of Strategic Petroleum Reserve estimated that in the year 2000, PADD V would import approximately 20 percent of its total petroleum requirements.

Department of Energy
Washington, DC 20585
May 13, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

On March 11, 1991, Robert H. Gentile, Assistant Secretary for Fossil Energy testified before your committee on Titles VII and VIII of S. 341.

At the time of my last letter to you dated April 17, 1991, we explained that the remaining question for the record was not available and that it would be forwarded to you. Enclosed is the answer to that question.

If we can be of further assistance to you or your staff, please contact our Congressional Hearing Coordinator, Renee Wilhite, on (202) 586-4277.

Sincerely,

Jacqueline Knox Brown
Assistant Secretary
Congressional and Intergovernmental
Affairs

Enclosure

QUESTION FROM MALCOLM WALLOP

Question 3.b: Under such circumstances why do you consider this a "taking" of property in the Constitutional sense? Would you provide a legal brief for the record?

Answer: The Department of Energy and its predecessor agency, the Federal Energy Administration, analyzed somewhat similar issues in the late 1970's in connection with proposal to implement an "Industrial Petroleum Reserve" pursuant to section 156 of the 1975 Energy and Policy Conservation Act (EPCA). In response to your request, we are providing the analyses prepared at that time. These analyses reflect an assessment, during a previous Administration, of the risks that a program implemented under EPCA section 156 might effect a compensable taking of property; they also contain recommendations on how to minimize those perceived risks. Of course, the provisions of title VII of S.341 differ in significant respects from those of EPCA section 156, and it would be necessary to analyze specific plans for the implementation of title VII in the light of the law as it has developed since the 1970's, in order to assess the risks that a compensable taking would result from such implementation.

→ AGB IPR file

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

August 16, 1976

OFFICE OF THE GENERAL COUNSEL

MEMORANDUM FOR THOMAS E. NOEL
ACTING ASSISTANT ADMINISTRATOR
STRATEGIC PETROLEUM RESERVE

FROM: ROBERT C. GOODWIN, JR.
ACTING ASSISTANT GENERAL COUNSEL
FOR INTERNATIONAL, CONSERVATION AND
RESOURCE DEVELOPMENT PROGRAMS

SUBJECT: QUESTIONS CONCERNING THE INDUSTRIAL
PETROLEUM RESERVE

On August 4, 1976, I sent you the answers to the questions concerning the Industrial Petroleum Reserve (IPR) which you had asked us to address. Subsequently, Michael Carosella of your staff asked that we address the legal issues reflected in a memorandum of July 22, 1976, from Stuart Rosenblum to Michael Carosella. The following are the answers to those questions.

1. What is the impact of the "taking" question on the IPR?

This is the most basic question affecting the IPR, since if the program leads to a "taking," and the government is required to compensate participants, then FEA must determine whether the costs of such compensation still justify proceeding with the program. To a considerable extent, the amount of compensation would depend on the actual features of the program giving rise to industry expense. However, since we can find no decided case involving circumstances similar to those of the IPR, many questions, if litigated, would be novel and their outcome unpredictable.

Assuming that a taking does occur, it would be in the government's interest to reduce any industry expense directly caused by the taking.

2. Does FEA have authority to require participants to use government-operated central storage facilities?

Nothing in the statute specifically prevents this, although a person might argue that absent some justifiable basis for the requirement, it would be unreasonable where he has adequate storage facilities of his own. Furthermore, if there is a taking, the costs of transporting oil to the facilities could be compensible, even if the facilities are provided cost-free.

3. Leasing requirements.

Section 159(f)(D) of the EPCA gives the Administrator leasing authority whicn is independent of that which can be delegated to an agency by GSA under 40 U.S.C. 484. As such, the requirements under that statute applicable to most government leases (e.g., advertisement, bids) would not affect leases implementing the IPR. Nevertheless, in order to minimize the possibility that the Administrator's actions under 159(f)(D) could be attacked as "arbitrary and capricious", the procedures under 40 U.S.C. 484 should be applied where practicable.

4. Can FEA compel companies to store oil other than that which was imported or refined during the base period?

Section 156(a) permits the Administrator to require storage of any type of oil, provided it meets the broad definition of "petroleum products" in the statute. However, this amount cannot exceed "three percent of the amount imported or refined by [each participant] during the previous calendar year." This leaves open the question of whether the maximum applies with respect to each commodity imported or refined (e.g., no more than 3% of the total xylene imported), or whether it applies in the aggregate (e.g., no more than 3% of the total barrels imported, with the mix to be determined by FEA). We would favor the latter approach, though the point would probably be litigated if a person were required to import and store material that he had never previously imported or were caused to change his refinery mix.

5. Can money be accepted in lieu of oil?

Absolutely not.

6. Limitation of stored products to certain categories.

The statute, which permits the Administrator to determine the "amounts" contributed, would appear to give the Administrator sufficient discretion to determine the categories of products to be stored.

7. Drawdown trigger.

Section 161(f) permits the Administrator to allow participants in the IPR to remove oil without a Presidential finding of supply interruption. However, this provision is intended to allow a person to reclaim his oil; it is not intended to allow drawdown and distribution under a "Distribution Plan" absent a Presidentially-declared emergency.

8. Distribution.

Distribution of IPR oil can be made to persons other than the owners of such oil, provided that the owners are compensated for the value of their oil. Expiration of the Emergency Petroleum Allocation Act would not affect this result, since allocation authority with respect to the Reserve is independent of that Act. However, if it does expire while the Reserve is still in effect, the requirement that its provisions be followed to the maximum practical extent would, of course, no longer apply.

→ CAB IPRC
Info - B

FEDERAL ENERGY ADMINISTRATION

September 1976

MEMORANDUM FOR BRUCE A. PASTERNACK
DIRECTOR
OFFICE OF POLICY AND PROGRAM COORDINATION

ATTENTION: DIANE CREED
ISSUES COORDINATOR

FROM: MICHAEL F. BUTLER
GENERAL COUNSEL (SIGNED) MICHAEL F. BUTLER

SUBJECT: ISSUE PAPER ON INDUSTRIAL PETROLEUM RESERVE (IPR)

We have reviewed the subject Issue Paper and have the following comments:

I. One of the most important aspects of the IPR issue is whether a court would find the IPR to be an unconstitutional "taking" and the extent to which an IPR can be structured in such a fashion as to minimize the risk of a court finding that there had been such a "taking" of oil requiring some level of compensation.

We have conducted considerable analysis of the Constitutional issues which are raised by the IPR. In addition, similar analyses have been done by others, including the Library of Congress.

cc: MFButler (1)
DGWilson (1)
JCBell (1)
RGoodwin (3)

RGoodwin:ba:9/17/76:#116393

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FEA-F-47 GPO 882-888

Our basic conclusions on the legal issues are as follows:

1. The IPR raises serious constitutional questions which are likely to be litigated.

2. If an IPR is adopted the agency's litigation posture would be improved if the IPR is structured in such a fashion so as to allow the companies involved to retain a certain control over their oil. One way to accomplish this would be to require minimum inventory levels (which could be integrated into the refiners' systems) rather than requiring segregated storage. In other words, the more the regulations are structured to allow refiners some use and control over their oil, the less likely a "taking" would be found.

3. Even if an IPR were found to constitute a "taking" the measure of compensation would likely to be similar to a "rental" value representing lost opportunity costs, since any "taking" would be temporary in light of the 1985 expiration of the statute and the fact that the stored oil would be available for use by the company concerned if a supply disruption occurred.

II. We support the establishment of an IPR for the following reasons:

1. Implementation of an IPR could, in fact, accomplish the objectives of regional storage without the disadvantages. If an IPR were to be implemented which gave all refiners and importers the choice to store oil wherever they chose, and also allowed the oil to be comingled with normal working stocks, it is likely that some importers would choose to use their own surplus storage capacity in the regions to meet the IPR requirement. To the extent that such storage capacity does exist, implementation of the IPR would be likely to result in some regional storage without costs to the Government.

2. Implementation of an IPR would have the advantage of reflecting the cost of storage in the cost of the product to be borne by those petroleum consumers most directly benefited by the storage program.

3. A program requiring only an increase in inventory levels could be fairly simply structured, and administered mainly through reporting requirements and periodic audits.

4. Increasing inventory levels would mean that for that portion of the total reserve held by industry, there would be no distribution problems. In effect, the oil has already been distributed.

5. Dispersion of at least some of the oil has some national security benefits.

6. The litigation risks apply only with respect to the compensation issue. Even if we were to lose a lawsuit on the IPR (which we do not consider likely) and thus have to pay for industry storage, many of the advantages of having industry store oil would still apply.

→ DAB IPRG

Bob

FEDERAL ENERGY ADMINISTRATION

MEMORANDUM FOR BRUCE A PASTERNACK
ASSOCIATE ADMINISTRATOR
POLICY AND PROGRAM EVALUATION

ATTENTION: DIANE K. CREED
ISSUES COORDINATOR

FROM: MICHAEL F. BUTLER
GENERAL COUNSEL

SUBJECT: INDUSTRIAL AND REGIONAL PETROLEUM RESERVES "MINIMUM INVENTORY" ISSUE PAPER

Attached, please find the comments of the Office of General Counsel on the subject issue paper. As noted in these comments, we believe that further analysis is required before a final decision can be made. We will be happy to work with the Strategic Petroleum Reserve Office and other relevant offices on these issues.

Attachments

cc: MFButler (2)
EJFygi (1)
JCBell (2)
RGoodwin (3) ✓

OGC:RGoodwin:bah:FB/rm5116/X566-9380/#116402
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COMMENTS ON ISSUE PAPER
No. 116402, "INDUSTRIAL AND REGIONAL PETROLEUM RESERVES"

1. It has been impossible, within the short time frame allowed, to analyze in any depth the multifaceted legal and policy issues presented by this paper. Moreover, we have an initial difficulty in understanding the basis upon which the specific options have been chosen, as each option is subject to a large number of possible variations.

2. In terms of the legal defensibility of an IPR, we believe that Option 4, which would require only importers of fuel oil to maintain an IPR, creates serious legal problems.

3. We see no legal objection to a voluntary minimum inventories program. It would appear, however, that a voluntary program would have little benefit since one could never be sure that the inventory level would remain at the target level. In addition, the monitoring which would be required would probably be comparable to what would be required for a mandatory program.

4. We do not believe that the paper addresses adequately the various ways in which an IPR could be structured as an inventory requirement. Indeed, the paper does not even list a mandatory inventory requirement (with or without increases) as one of the options.

With respect to establishment of an inventory, Section 458 of the EPCA does provide independent authority for such a program (though only if the President "finds an existing or impending regional or national supply shortage of any fuel"). We believe, however, that a comparable program could be implemented pursuant to EPCA §156 (the section authorizing an IPR), with the amounts thus stored counted as part of the SPR, and even toward RPR goals.

Under §156 of the EPCA the Administrator is authorized to require refiners and importers to store petroleum in "readily available inventories." This term is defined to mean "stocks and supplies of petroleum...which can be distributed or used without affecting the ability of the importer or refiner to operate a normal capacity; such term does not include minimum working inventories or other unavailable stocks." According to the Issue Paper there are currently about 100 million barrels of crude oil held in inventory which could be defined as "readily available inventories." Residual fuel inventories are estimated at 20 million barrels above minimum levels. One of the initial decisions which must be made, therefore, is whether FEA desires to credit that 120 million barrels or some portion thereof toward the Strategic Petroleum Reserve.

The legal problems associated with an IPR program would be lessened if subject firms were free to use their stored oil in the normal course of business, subject only to a requirement that they maintain inventories at a certain level; firms might be permitted to store a part of their inventories in central storage, if they chose to do so, and possible financial incentives could be structured to induce them to do so. A number of details would have to be worked out with the legal problems in mind, including selection of the firms to be subjected to the storage requirement, identification of an appropriate base period, determination of the means of auditing, and adjustment of the import license fee (from which IPR imports are exempted).

There is no doubt that implementation of an IPR along these lines would present a number of administrative difficulties. These difficulties should be evaluated to determine whether they outweigh the advantages gained from having an assured inventory level available.

It should be noted that whether or not the inventory level which is required to be maintained is above the current industry stock levels is a question which can only be addressed after the basic decision is made. Once the decision is made as to whether industry should be required to hold inventories, then, if that decision is to require inventories, we can analyze current levels, existing excess steel tank capacity, etc., to determine the appropriate level of inventories to require.

Craig

→ IPR file

Department of Energy
Washington, D.C. 20461

June 22, 1978

MEMORANDUM FOR DAVID BLOOM

FROM: ROBERT C. GOODWIN, JR.

SUBJECT: IMPLEMENTATION OF INDUSTRIAL PETROLEUM RESERVE AUTHORITY

You have asked for our legal judgment with respect to issues associated with the Industrial Petroleum Reserve (IPR).

Section 156(b) of the Energy Policy and Conservation Act (P.L. 94-163) provides that the Administrator (now the - Secretary of Energy pursuant to the provisions of the Department of Energy Organization Act) may establish an Industrial Petroleum Reserve (IPR) as an aid in implementing the Strategic Petroleum Reserve mandated by the Act. Under the IPR, the Administrator:

> "may require each importer of petroleum products and each refiner to (1) acquire, and (2) store and maintain in readily available inventories, petroleum products in amounts determined by the Administrator, except that the Administrator may not require any such importer or refiner to store such petroleum products in an amount greater than three percent of the amount imported or refined by such person, as the case may be, during the previous calendar year."

Under Section 531, the Strategic Petroleum Reserve would expire with the general expiration of the Act of June 30, 1985.

The question of whether the IPR constitutes a "taking" by the Government of private property, for which the Fifth Amendment requires compensation, was examined by the Library of Congress, which concluded that the program was a permissible exercise of the government's commerce power which could survive constitutional challenge as a taking. However, the study conceded that the manner in which FEA implemented the program could alter its conclusions, in that while Congress envisioned a public welfare measure it is well established that if its terms became so burdensome, so disproportionate to the interest served, it could become a taking. Nichols, The Law of Eminent Domain, J. Sachman ed. (New York, 3rd rev. ed. 1964) §1.42.

Attached is an analysis prepared by my staff which essentially agrees with the findings of the Library of Congress. The analysis notes that regulation of oil and gas through conservation statutes and other types of regulation have a long history. The courts have consistently upheld the power of states to exercise their police power in limiting an individual's discretion with respect to the use of his oil and gas property. It is important, however, that the distinction between exercise of police power and exercise of eminent domain power be retained. The distinguishing characteristic between eminent domain and police power is that the former involves taking property because of its need for the public use, while the latter involves regulation of such property to prevent the use thereof in a manner detrimental to the public interest. If in the exercise of the police power property is taken or damaged, it is not a taking or damaging for public use, but to preserve the safety, morals, health, and general welfare of the public.

In our view, a sound argument can be made that an Industrial Petroleum Reserve is not a taking but is a regulation of the use of petroleum to preserve the public safety and general welfare. However, in order to be able to characterize an Industrial Petroleum Reserve as a legitimate exercise of police power which regulates rather than takes, it should be structured in such a way so that the owners of the oil retain some control and interest in the property.

We recommend that the following specific concepts be incorporated in any Industrial Petroleum Reserve Plan:

(1) Some use of the oil in question should be available to the owner such as the right to mortgage the oil against its later release or sale so that the oil can remain as part of the company's useful inventory.

(2) Flexibility should be built into any program. Thus, if DOE desires centralized storage, this would best be accomplished by making such storage available for lease to oil companies who would otherwise be required to store in their own facilities. By giving companies the option to meet the Industrial Petroleum Reserve requirements either through their own storage or through centralized storage, we have such flexibility.

(3) The Industrial Petroleum Reserve regulations should be structured to allow companies to minimize costs.

In addition to the specific suggestions outlined above, there will undoubtedly be other approaches which will become clear in the structuring of any Industrial Petroleum Reserve program. The important point to be borne in mind is that any Industrial Petroleum Reserve program should be structured so as to avoid the total loss of control and interest by the oil companies in the oil involved.

Attachment

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CONSTITUTIONAL ISSUES REGARDING IMPLEMENTATION OF AN INDUSTRIAL PETROLEUM RESERVE (IPR)

DRAFT

I. Police Power in Oil and Gas

The constitutionality of legislation regulating the production, use, storage and transportation of oil and natural gas has been readily sustained by the courts. It is within the government's police power to enact and enforce legislation to protect the public interest in natural resources, to prevent or abate nuisances, and to safeguard the correlative rights of owners of land within a common source of supply of oil and gas. Conservation legislation and its resultant regulations have withstood charges of taking private property without due process and just compensation, denial of equal protection, impairment of the obligation of contracts and interference with the liberty of contract by setting the prices of oil and gas.

Early Statements of Public Interest

Early expressions of the public interest in oil and gas as natural resources can be found in the first conservation statutes, which require the plugging of abandoned wells and prohibit wasteful utilization and the escape of gas. One of the first restrictions placed on the use of natural gas was by statutes in a number of states forbidding the burning of natural gas in flambeau lights and requiring that gas lights, burning in the open, be turned off during the day time. Obviously, the statutes and regulations were intended to prevent the waste of natural gas. The 1940 Code of Alabama, 1917 Arkansas Statutes, 1949 Kansas Statutes, the Ohio, Oklahoma and Texas Codes all state that this prohibited act "is a wasteful and extravagant use, and dangerous to the public good." In other states, statutes which restricted wasteful uses of gas for illumination have been repealed by later conservation statutes defining and prohibiting waste of oil and gas.

When the constitutionality of conservation statutes was first questioned, the courts sustained such legislation as a valid exercise of the state's police power to protect a public interest. State v. Ohio Oil Co, 49 N.E. 809, 150 Ind. 21 (1898) concerned a statute which prohibited the escape of gas into the air for a period longer than two days after its discovery. In that opinion the court stated that "[t]o use appellee's wells as they have been doing, they injure thousands, and perhaps millions, of the people of Indiana, and the injury -- the exhaustion of natural gas -- is not only an irreparable one, but it will be a great calamity." In Ohio Oil Co. v. Indiana, 20 S.Ct 576 (1900), the Supreme Court upheld a statute prohibiting the waste of gas by escape from wells as a valid exercise of police power to protect the correlative rights of the owners in a common source of supply of oil and gas. The existence of correlative rights indicates that each owner in a common source of supply is entitled to his proportionate share, but may not take an undue proportion. Oil and gas "Have no fixed situs under a particular portion of the earth's surface within the area where they obtain. They have the power as it were of self transmission. No one owner of the surface of the earth, within the area beneath which the gas and oil move, can exercise his right to extract from the common reservoir, in which the supply is held, without, to an extent, diminishing the source of supply as to which all other owners of the surface must exercise their rights." Ohio Oil Co v. Indiana, 20 S.Ct. at 581.

Police Power Used for Conservation

Conservation legislation has also been sustained as a valid exercise of police powers without relying on the concept of correlative rights. The California court said in People v. Associated Oil Co., 294 P. 717, (1930), in upholding the imposition of a gas-oil ratio, "whatever refinements may be suggested as to the definition of the nature of the property right in gas and oil beneath the surface and uncaptured, we are entirely satisfied that the waste of these natural resources may be regulated and the unreasonable waste thereof may be prohibited in the exercise of the police power of the state."

In Texas, where the landowner is considered to own the oil and gas in the ground, and the lessee to have a determinable fee interest therein, the courts have stated that these property theories concerning oil and gas do not affect the constitutionality of the oil and gas legislation. As the following cases show, the concept of correlative rights is not determinative of the validity of exercising police power to impose conservation statues. The courts recognize, even in the 1930's, the necessity to conserve the country's national resources. Thus, in Henderson, Inc. v. Railroad Commission of Texas, (D.C. Tex., 1932) 56 F.2d 218, in upholding a statute prohibiting the blowing of gas into the open air and regulating the uses of gas, the court said:

"We do not agree with the plaintiff that the fact that the rule in Texas which recognizes the ownership of oil and gas in place and gives to the lessee a determinable fee therein, (. . .) operates at all to deprive the state of the power to conserve its natural resources, or to limit the reasonable exercise of that power. We are not in doubt that both upon considerations of securing and prescribing the correlative rights of persons in property, though owned by them, of the shifting and fugacious kind which oil and gas is, and upon considerations of conserving the natural gas resources of the state, ample power exists in the Legislature to prevent the wasteful utilization of oil and gas, and to regulate and control their production and use in such reasonable way as to bring about their conservation, and to prevent their dissipation by waste." Danciger Oil & Refining Co. v. Railroad Commission (Civ. App., 1932) 49 S.W.2d 837, held the oil conservation act and orders of the Railroad Commission restricting and prorating production of oil to be valid. The court said "[n]or do we think this interest, nor the power of the state to conserve such resources, is minimized in the least by the fact that in Texas these minerals are considered as owned in place by the owner of the surface, rather than that a community ownership in a common pool or deposit exists, as is held in some other states. The power of the State to conserve them, where the public interest demands it, undoubtedly exists in either case."

Finally, in Walls v. Midland Carbon Co., 41 S. Ct. 118 (1920), the Court held that it is within the police power of the state to regulate the use of natural gas drawn from wells so as to preserve the natural resources. In this case, the company was solely interested in producing oil, and it used the gas as "power, force and agency" to raise the oil to the surface of the ground, thereafter permitting the gas to escape. The Court recognized the "power of the state to interpose its power to prevent a waste or disproportionate use of either oil or gas by a particular owner, in order to conserve the equal rights of other owners and to advance the public interest." Furthermore, the Court held that the state's action prohibiting the use of natural gas for the manufacture of carbon or other products, without using the heat generated thereby for other industrial or domestic purposes, is within the police power of the state, to prevent waste of natural resources. The question of the relative value of the use of natural gas for the production of carbon and for industrial and domestic purposes is one for the State to decide, in the exercise of its police power, to conserve its natural resources. It can prohibit the use of such gas for manufacturing, even though it appears that the value of the carbon exceeds the value of the gas for fuel.

Unit-Pooling

Many current conservation statutes now define waste to include the inefficient, excessive, or improper use or dissipation of reservoir energy. In such states, the conservation agencies are authorized to make rules and regulations governing the use of reservoir energy, including the establishment of gas-oil ratios. However, gas-oil ratios, spacing and location of wells on the structure, maintenance of back pressure on oil wells, cycling and recycling of gas, and the introduction of gas, water or other substances into the producing formation for renewal of reservoir pressures cannot be effectively used if surface property lines must be followed. To use such procedures, all or a portion of a common supply source must be developed as a unit and the production apportioned among the lessees and royalty owners upon some fair and equitable basis.

An oil and gas conservation statute, defining waste and giving the conservation agency authority to issue and enforce rules and regulations for the prevention of waste, does not give that agency the authority to order the unitization of all interests in an oil and gas pool. The court in *Dobson v. Arkansas Oil and Gas Commission*, 235 S.W. 2d 33 (1951), after considering various sections of the Arkansas statute, held that the legislature had not authorized the conservation agency to order the unitization of an entire oil and gas field. Thereafter, eleven states (Alabama, Alaska, Arkansas, Florida, Georgia, Louisiana, Nevada, Oklahoma, South Dakota, Utah and Washington) enacted statutes which authorize their state conservation agencies to compel formation of oil or gas pool on private lands. Some statutes are limited to the authority to compel unitization for pressure maintenance and repressuring operations, while others allow any plan of operation which will prevent waste and protect correlative rights. The constitutionality of Oklahoma statute, the first enacted, and orders issued under it were upheld in Palmer Oil Corp. v. Phillips Petroleum Co., 231 P.2d 997 (1951) and Spiers v. Magnolia Petroleum Co., 244 P.2d 843 (1952). The federal government has adopted a similar approach with a statute (30 U.S.C.A. §226(e)) authorizing the Secretary of the Interior to issue regulations requiring that all future oil and gas leases issued under the provisions of the Mineral Leasing Act contain a provision requiring the lessee to operate under a reasonable unit plan prescribed by the Secretary.

In Crichton v. Lee, 25 So. 2d 229 (1946), the Louisiana court held that Act 157 of 1940, permitting compulsory drilling units and unit authorization, was constitutional as an exercise of the police power to prevent waste and depletion of natural resources. The court also held that the application of a complusory pooling order to a lease executed before enactment of the statute so as to extend the primary term thereof by a well drilled on the unit did not impair the obligation of contracts.

Another Louisiana case, Everett v. Phillips Petroleum Co., 51 So. 2d 87 (1951), held that the statute authorizing the conservation agency to establish drilling units and to require unit operation of separately owned tracts embraced within a drilling unit did not violate any provision of the state or federal constitution. Croxton v. State, 97 P.2d 11 (1940) upheld an Oklahoma statute as valid exercise of police power; the order establishing drilling units was not discriminatory and did not deny equal protection of the laws to the owners of mineral rights thereby affected merely because it placed in operation over the common source of supply the statute which regulates the production of wells.

In all these cases, the court regards as paramount the state's interest in efficient and maximized development of its natural resources. This takes priority over an individual's desire only to develop oil reserves on his land or not to drill at a particular time. The state has the authority through its police power, to order an individual or a company to participate in such a unit drilling plan and thereby to forego control over his rights to the oil and gas. Clearly, that individual receives the fair market value for his share of the oil and gas, but he has lost his right to determine when or where to drill for his share of the common source of supply.

Spacing of Wells

The rule of the Texas Railroad Commission governing the spacing of wells, commonly known as Rule 37, derives from authority given by the Texas Conservation Act of 1919. The rule prohibited the drilling of a well nearer than 300 feet to another well or nearer than 150 feet to any property line, but exceptions would be granted upon petition, hearing and notice, for good cause. Rule 37 has been repromulgated and amended many times; for example, the commission may grant exceptions to prevent waste or to prevent the confiscation of property; and wells drilled in violation of the rule without permit, or in a manner not conforming to the permit granted, shall be plugged, however, its essential purpose remains the same. The Rule 37 has been upheld by the courts as a valid exercise of police power to prevent the waste of natural resources. The court in Oxford Oil Co. v. Atlantic Oil and Producing Co. (D.C. Tex. 1926), 16 F. 2d 639, affirmed, (5 Cir., 1927) 22 F. 2d 597, cert. denied 48 S. Ct. 433 (1928), stated of this rule that "[w]e must not limit police power to such legislation as will serve to operate upon the safety and liberty and health of the citizen. The variety of cases in which the exercise by one individual of his rights may conflict with a similar exercise, is multitudinous, and the courts have not found it impossible to uphold police legislation that prevents such trespass." 16 F.2d at 643. See also Tysco Oil Co. v. Railroad Commission of Texas, (D.C. Tex. 1935) 12 F. Supp. 195.

Other jurisdictions besides Texas have also imposed valid spacing requirements on the placement of oil wells. See Marrs v. City of Oxford, infra, 24 F. 2d 541 (1928).

Spacing requirements require some parties to forego their right to drill at all if there is another well nearby. The courts have found that, as in the unitization cases, there is a valid state interest in conserving natural resources to protect the security of social order, beneficial use of property and public safety, which overrides the individual's property rights.

The IPR program is intended to establish a national storage capacity for drawdown during an emergency in accordance with an appropriate Distribution Plan established under Section 154(12) of the Energy Policy and Conservation Act (P.L. 94-163). The program is part of implementing the Strategic Petroleum Reserve, in response to the Arab boycott of 1973-74. The possibility of another boycott or other event interrupting the flow of foreign oil is both unpredictable and very real, calling for national emergency preparedness to minimize the certain impacts which the entire economy, would suffer. In the 1970's, the need to conserve natural resources is markedly greater than in the 1890's or 1930's when the courts sustained the government's right to conserve resources and minimize waste by imposing unitization or spacing requirements. A strong argument can be made that, historically, courts have recognized a particular need to conserve and develop oil and gas resources which justifies the exercise of a state's police power by limiting a land owner's right to use or waste those reserves. One purpose of the IPR program is the same; the conservation of domestic resources by the development of industrial petroleum reserves. Another purpose, the protection of the domestic economy from the adverse imports of an oil embargo, is even more directly related to the public health and safety which is the legitimate realm of police power.

II. General Discussion of Police Power

The courts recognize that the state may make a valid exercise of police power to protect the public interest in conservation of oil and gas, while those resources are still in the ground or being withdrawn, however, it is not so obvious that a court will sustain the imposition of mandatory storage requirements for petroleum. on the same basis. This petroleum has already been removed, is in the commercial stream, and may not ever have been an American natural resource. This section discusses the use of police power in general so as to provide guidelines for the implementation of sustainable IPR regulations. There is a strong argument in favor of mandatory storage based on the historical exception which courts have granted to the exercise of police power was to conserve and develop natural resources. In addition, the direct relationship of a reserve to the public health and safety argues strongly that imposition of an IPR would be upheld. Care must be taken to institute regulations which are clearly within the traditional framework of police power, to strengthen the case for the IPR program being a non-compensible taking as part of the government's police power.

Police power traditionally extended to the public health, safety and morals. Larrabee v. Dolley speaks of police power as a last resort of necessity in protection of life, comfort, safety and welfare of society. 175 F. 365, 389. However, courts today view police power more broadly. The state can impose regulations, based on its police power, to promote general prosperity, public convenience, development of resources, contributions to general societal wealth, and even fish culture. See Slyman v. Fisheries and Game Commission, 97 NE 663, which sustained the flooding of lands in order to create or raise a pond as a valid exercise of the state's police power.

No One Definition of Police Power

The courts have traditionally avoided defining exactly the term "police power." In the Slaughter House Cases, 83 U.S. 62 (   ), the Court spoke of the necessity of vague definition since the security of the social order, life and health, citizens' comfort and existence in a thickly populated community, the enjoyment of private and social life and the beneficial use of property all depend on the state's use of police power.

"An attempt to define its reach or trace its outer limits is fruitless for each case must turn on its own facts. The definition is essentially the product of legislative determinations addressed to the purposes of government, purposes neither abstractly nor historically capable of complete definition. Subject to specific constitutional limitations, when the legislature has spoken, the public interest has been declared in terms well-nigh conclusive." Berman v. Parker, 75 S. Ct. 98, 102.

Furthermore, §156(b) of the EPCA, the section establishing the IPR, significantly makes no mention of compensation to be paid to the oil companies by FEA. It simply states that the Administrator may require each importer and refiner to acquire, store and maintain readily available reserves. This omission of compensation, by Congress, should be given great weight by the courts in light of traditional judical acknowledgment of legislative intent in the exercise of police power. Debatable questions as to the reasonableness of the use of police power are not for the courts but for the legislature. Sproles v. Binford, 52 S. Ct. 581, 585

(1932). However, this does not mean that the courts defer blindly to the legislature. "The greatest weight is given to the judgment of the legislature but it is always open to interested parties to contend that the legislature has gone beyond its constitutional power." Pennsylvania Coal Co. v. Mahon, 435. Ct. 159 (1922).

The expansion and sophistication of the concept of police power is continuous. Police power can be extended to regulate an area which, due to changed circumstances, might now infringe on the public interest. A reasonable business today may be a menace tomorrow. Dobbins v. Los Angeles, 25 S. Ct. 18 (1904). A Texas court has stated that an oil operator acquired no "vested right" in spacing rules which were in effect at the time his tract was segregated and the lease acquired. The very nature of police power, from which the state derives its right to regulate the production of oil and gas, subjects such rules to change from time to time to permit fair and equitable adjustment of the machinery of oil proration to meet changing conditions. Texas Trading v. Stanolind Oil & Gas Co., 161 S.W. 2d 1046-1047.

As these cases illustrate, the definition of police power is not static; the scope of legitimate exercise of police power is therefore capable of expansion by movement in another direction such as mandatory storage of industrial petroleum reserves as part of the nation's emergency preparedness.

Eminent Domain versus Police Power

It should be recognized that there are in fact limits placed upon the use of the police power by the Fifth Amendment. "As long recognized some [property] values are enjoyed under an implied limitation and must yield to the police power. But obviously the implied limitation must have its limits or the contract and due process clauses are gone." Pennsylvania Coal Co. v. Mahon, 43 S. Ct. 158, 159 (1922). At such a point, the state has crossed the thin line separating police power from eminent domain. The distinguishing characteristic between eminent domain and police power is that the former involves taking property because of its need for the public use while the latter involves regulation of such property to prevent the use thereof in a manner detrimental to the public interest. Nichols, Law of Eminent Domain, §1.42(2) (3d Ed. 1950). "Eminent domain takes private property for public use while the police power regulates its use and enjoyment, or if it takes or damages it, it is not a taking or damaging for public use but to conserve the safety, morals, health and general welfare of the public." City of Los Angeles v. Aitken, 52 P.2d 585, 590. In Appeal of White, 134 A. 409, 411, the court stressed another distinction between the two. "Police power controls use of property by the owner for the public good, its use being otherwise harmful; no payment being made for diminution in use even though it amounts to an actual taking or destruction of property. Eminent domain takes property for public use and gives compensation for property taken, injured or destroyed."

The intent of the IPR program is to establish reserves which will be returned to the contributors when the program expires in 1985: in the event of an emergency, the intent is still to return the petroleum to its owners unless some allocation program is in effect, in which case, they would be compensated.

The IPR program does not envision the government taking and using the petroleum itself. It is not a taking for public use but a regulation of the petroleum industry mandating the establishment of reserves. Furthermore, unrestricted use of the petroleum, without reserves as protection in the event of an Arab boycott or other interruption of petroleum imports, is not in the public's interest. Establishment of the reserves is part of a program to protect the national safety and welfare.

Actual physical appropriation need not occur to invoke the requirement of just compensation if the legislation in issue is so unreasonable or arbitrary as virtually to deprive a person of complete use and enjoyment of his property through destruction or severe impairment. See Welch v. Swasey, 214 U.S. 91 (1909), Pennsylvania Coal Co. v. Mahon, 43 S. Ct. 158 (1922), Goldblatt v. Hempstead, 369 U.S. 590 (1962). Property is taken in a constitutional sense whenever such inroads are made upon the owner's use of it that, as between private parties, a servitude is acquired either by agreement or in the course of time. U.S. v. Dickinson, 331 U.S. 745, 748 (1947).

In United States v. Causby, 66 S. Ct. 1062 (1946), military planes constantly flew so low over the plaintiff's land that he was deprived of the use and enjoyment of his land for purposes of raising chickens. This constant intrusion on the use of the land constituted a taking entitling him to compensation. Similarly, in United States v. Kansas City Life Ins. Co., 70 S. Ct 885 (1950), the Court held that construction of the dam which maintained the river constantly at high water mark, flooding the plaintiff's land entitled the plaintiff to compensation as a result of the "taking". In neither of these cases, did the government attempt to show that these actions came within the police power. It might indeed be difficult to argue that flying low over a chicken farm served the public interest or protected the health of the community. Nonetheless, for this reason, a distinction exists between these cases and the IPR program, which is intended to protect the general safety and welfare.

To escape the requirements of compensation in the case of eminent domain, the IPR regulations must clearly demonstrate this distinction; that they serve a legitimate expression of police power, as public safety, general welfare, and development of resources. The purpose of the IPR statute must be shown to be the regulation of industrial petroleum so as to prohibit its being used in a manner detrimental to the public interest, so that it is clearly not a "taking" for the public use.

Is it a Burden to be Borne by Public as a Whole?

The Fifth Amendment guarantee that private property should not be taken for a public use without just compensation was designed to prevent the government from forcing some people alone to bear public burdens which, in all fairness, should be borne by the public as a whole. Armstrong v. U.S. 364 U.S. 40, 48-49 (1960).

However, in another case the Court states that "[i]t is true that police power embraces regulations designed to promote public conveience or the general welfare, and not merely those in the interest of public health, safety and morals. . . . But when particular individuals are singled out to bear the cost of advancing the public convenience, that imposition msut bear some reasonable relation to the evils to be eradicated or the advantages to be secure." Nashville, C. & St. L. Ry. v. Walters, 294 U.S. 405, 429 (1935).

In light of the language in these cases, implementation of the IPR program should attempt to minimize the burdens to be borne by the oil companies. Consideration should be given to the possibility of allowing the companies to pass through some of the costs, storage, transportation, lost revenues, insurance, to the consumers so that they are not bearing a public burden alone. In addition, minimization of costs, either by use of inventory stock or allowing the companies to store the oil in government facilities, will bring the costs into a reasonable realtion to "the advantages to be secured".

Courts have looked at the extent of diminution of the value of property to determine whether a taking had occurred. "When it reaches a certain magnitude, in most if not all cases there must be an exercise of eminent domain and compensation to sustain the act. The question depends upon the particular facts." Pennsylvania Coal Co. v. Mahon, 43 S. Ct. 158, 159 (1922). However, in Hadacheck v. Sebastian, 36 S. Ct. 143 (1915), a statute prohibiting the use of certain property as a brickyard, was upheld even though its effect was to reduce the value of the property from $800,000 as a brickyard to $60,000 for residential purposes. Therefore, although a comparison of the values of the property both before and after is relevant, it is by no means conclusive. Nonetheless, wherever possible, the implementors of the IPR program should attempt to leave as much value as possible to the oil, so as to avoid the language in Mahon. If the oil were part of the companies' inventories, this would be the case. If the oil could be mortgaged or title transferred, it would still have value to the companies. Finally, unlike the property in Hadacheck, by 1985, when the program expires the price of oil will no doubt have increased, so that the value of the property returned to the refiners and importers will be greater than that which they initially stored.

Reasonableness Standard Applies

The DOE cannot use the police power to impose unusual or unnecessary restrictions on individual liberties, lawful occupations or private business. See Ex Parte Drayton 15 F. 986, 989. The means used to exercise the police power must clearly be reasonable and necessary for the accomplishment of the purpose as opposed to arbitrary or oppressive upon individuals. Lawton v. Steele, 14. S. Ct. 499, 501 (1894). In re Horse 70 F. 598, 509. However, the court in Lawton goes on to state that "[while the legislature has no right arbitrarily to declare taht to be anuisance which is clearly not, a great deal must be left to its discretion in that regard; and, if the object to be accomplisehd is conducive to the public interest, it may exercise a large liberty of choice in the means employed" 14 S. Ct. at 502.

It should be noted, however, that the contesting party contending that the statute or ordinance is not a valid police measure has the burden on issues of reasonableness. Goldblatt v. Town of Hempstead, 82 S. Ct. 987, 991 (1962). Furthermore, the exercise of police power will be upheld if any state of acts either known or which could be reasonably assumed affords support for it. United States v. Carolene Products Co., 58 S. Ct. 778, 784 (1938). Every possible presumption is to be indulged in favor of the validity of the statute. Sinking Fund Cases, 99 U.S. 718 __________.

Finally, the Court discussed the types of information necessary to determining the reasonableness of an ordinance. In Goldblatt v. Town of Hempstead, New York, the Court stated that to evaluate the reasonableness of the ordinance, it needed to know the nature of the menace against which the ordinance will protect, the availability and effectiveness of other less drastic steps and the loss which the appellants would suffer from imposition of the zoning ordinance which prohibited operation of their sand and gravel pit. 82 S. Ct. 987 (1962). The meance against which the IPR program will protect is clear; complete disruption of the economy. However, the program must strenuously avoid imposition of any unnecessary burdens on the refiners and importers so that they suffer the smallest loss possible.

Public Interest

In Pennsylvania Coal Co. v. Mahon, the Court refused to uphold a statute whose effect was to protect one house from damage while prohibiting mining of coal under streets, even though the right to mine the coal in those places has been expressly reserved to the mining company by the city. The

Court stated that: "[t]he extent of the public interest is shown by the statute to be limited, since the statute ordinarily does not apply to land when the surface is owned by the owner of the coal. Furthermore, it is not justified as a protection of personal safety. That could be provided by notice. . .the statute does not disclose a public interest sufficient to warrant so extensive a destruction of defendant's consistently protected right. (Emphasis added). Penn. Coal Co. v. Mahon, 43 S. Ct. at 159.

In this case the public interest did not warrant such extreme interference, but the Court implicitly recognizes that cases do exist in which protection of the public interest requires the use of police power; for example, the conservation statutes which are intended to protect and develop national resources. The IPR regulations are another instance in which the public interest warrants such interference. If no petroleum is stored, the nation is extremely vulnerable to the interruption of oil imports.

Safety

Instances in which a house is destroyed during a fire to prevent the further spread of the fire, which threatens the entire community, is a recognized common-law use of the police power to promote general safety. Bowditch v. Boston, 101 U.S. 16, 18-19 (1879). U.S. v. Caltex, 73 S. Ct. 200, 201, n.6 (1952). Similarly, an ordinance which required that storage tanks of a certain size for gasoline etc., was upheld as a legitimate exercise of the city's police power, as applied to tanks so located that much property and many people were within a potentially destructive radius, if fires or explosions occurred. City of Marysville v. Standard Oil Co., (8th Cir. 1928) 27 F. 2d 478. The destruction by U.S. Ary of a building in Cuba believed to contain germs of a contagious disease (yellow fever) during the Spanish-American War was upheld in Juarazera Iron Co. v. United States on the basis that the safety of the state in such cases overrides all considerations of private loss. 29 S. Ct. 385 (1909). It was believed that the troops were in danger of contracting yellowing fever, which would of course affect their ability to fight.

In Mugler v. State of Kansas, 123 U.S. 632 (1882) a statute prohibiting the manufacture and sale of liquor was sustained by the following language: "The power which states have of prohibiting such use by individuals of their property as will be prejudicial to the health, the morals, or the safety of the public, is not, and consistently with the existence and safety of organized society, cannot be burdened with the condition that the state must compensate them for primary losses they may sustain, by reason of their not being permitted, by a noxious use of their property, to inflict injury upon the community.

Precautionary Measures

The state is also permitted to exercise its police power by enforcing certain precautionary measures to protect the public health and safety. Therefore, a reasonable regulation by the board of health may be imposed to protect the public from invasion of epidemic disease. Jew Ho. v. Williamson, 103 F. 10, 20. Local health officials are entitled to examine persons arrested by lawful warrant for vagrancy, prostitution, rape or other sex crimes for the purpose of determining if they are infected with veneral disease. Ex parte Fowler, 184 P. 2d 814.

An authorized reasonable regulation, not unlawfully discriminatory which prohibits the keeping of oil, gasoline, gun powder and other explosive and inflammable and therefore dangerous, substances for sale near churches, hospitals, schools, and other buildings is sustainable as a proper exercise of police powers. Boothby v. City of Westbrook, 23 A. 2d 316, 318. A law requiring the vacination of children as a condition of their attendance in schools is also sustainable. Viemeister v. White, 84 N.Y.S. 712, 716, 88 App. Div. 44; Stull v. Reber, 64 A. 419, 421, 215 Pa. 156.

In Panhandle Eastern P. Line Co. v. State Highway Commission, 55 S. Ct. 563 (1935), the Court supported Panhandle's refusal to make certain ordered changes in its buried pipeline, on its own line, to accomodate highway improvements, without compensation. The Court distinguished this situation from intersetions of highways and railroad crossings because the record failed to disclose that the pipeline presented a serious danger to the public. "The rule in respect of railroad crossings applies when there is substantial risk of injury to the public from the operation of trains and ground to imply the company's consent to take such measures as may be necessary to prevent the hazard. This Court has not sanctioned extensions of the rule to wholly dissimilar circumstances; it does not apply to structures which are unattended by serious danger to the public." Id at 567.

A Pennsylvania statute which required that a pillar of coal be left along the line of adjoining property with a pillar of coal on the other side of the line was upheld in Plymouth Coal Co. v. Pennsylvania, 34 S. Ct. 359 (1913). The Court found that the two pillars would be a sufficiently wide barrier for the safety of employees of either mine in case the other should be abandoned and allowed to fill with water. "In effect, [the statute] requires a comparatively small portion of the valuable contents of the vein to be left in place, so long as may be required for the safety of the men employed in mining upon either property." Id. at 361. Aspects of this case are strikingly similar to the IPR program. Certain amounts of coal cannot be mined, but instead must be left in the ground, in a type of forced storage until both mines are closed. This is a significantly less definite time schedule than the IPR program expiration date of 1985. The Court sustained this exercise of police power which prevented the mining companies from using certain quantities of coal in order to guarantee the safety of miners from an accident which might never occur. The IPR program seeks to restrict the use of a quantity of industrial petroleum by use of police power to protect against a potential oil embargo.

Fire zone and building ordinances are another example of emergency preparedness which has been upheld by the courts as a valid exercise of police power. While the likelihood of any one building being set on fire is slight the city is still able to impose construction or remodelling restrictions on all buildings to guard against such an occurrence. Engle v. City Com'rs of Cambridge, 22 A.2d 992, 925.

There is substantially more likelihood of an oil embargo than a fire in a particular building or a smallpox epidemic. The IPR regulations which provide protections against the effects of that possible embargo can be sustained as a exercise of police power for national emergency preparedness.

Widespread Public Damage Suffered

The courts often look at the potential damage which will be suffered in the absence of an exercise of police power.

One reason given for striking down the mining restriction in Pennsylvania Coal Co. v. Mahon was that the damage being protected against was neither "common nor public". A source of damage (sinking) to the house in question was not a public nuisance even if similar damage is inflicted on others in different places. Penn. Coal at 159.

The location of gasoline storage tanks which were in issue, their proximity to homes, theatres, hotels and businesses, and the frequency of fires and explosions due to gasoline storage tanks in recent history were considered by another court to determine the potential damage in abasence of the ordinance. Against this information was weighed evidence that it is possible to bury several types of gasoline storage tanks underground successfully without leakage or dangerous vaporization. In view of the slight cost and burden to the owners of the gas tanks and the great risk of fire and explosion with much resulting damage. The court sustained the ordinace as a valid exercise of police power. City of Marysville v. Standard Oil Co. (8th Cir. 1928), 27 F.2d 478.

Finally, the Supreme Court upheld the World War II demolition of oil companies' terminal facilities in Manila by U.S. Army personnel when Japanese troops were entering Manila. The facilities were destroyed for the single purpose of preventing the enemy from using the petroleum products to wage war more successfully. According to the Court, this did not constitute a compensable taking for public use. United States v. Caltex, 73 S. Ct. 200 (1952).

The intended purpose of the IPR program is to minimize the ramifications of an oil boycott or other importation interruption. The experience of the 1973-74 boycott certainly should establish that there is a likelihood of serious and widespread public damage unless preparations are made to guard against its effects. That the program can be sustained as a valid exercise of police power to protect the public safety and general welfare is strengthened, therefore, when the potentialimpacts of a boycott are considered.

Development of Prosperity and Resources

While the courts often uphold the restriction or destruction of an industry as an exercise of the police power (Mugler v. Kansas, prohibition of manufacturer of liquor, United States v. Central Eureka Mining Company, 78 S. Ct. 1098 (19), restriction of gold mining to divert valuable resources to the war effort), another purpose of police power is to encourage the development of a state's resources and its wealth. The purpose of many of the oil and gas conservation statutes discussed above is precisely directed to the conservation and development of natural resources by maximizing production.

An 1884 San Francisco ordinance prohibited the indiscriminate establishment of public laundries and wash-houses because they endangered the public health and safety, prejudiced the well-being and comfort of the community, and depreciated the value of property in their neighborhood. The Supreme Court, in upholding the requirements that certificates be obtained from the city health officer and fire warden, stated that the 14th Amendment was not designed to interfere with the state's police power "to prescribe regulations to promote the health, peace, morals, education, and good order of the people, and to *legislate so as to increase* the *Industries of the state, develop its resources, and add to its wealth and prosperity*." (Emphasis added). *Barbier* v. *Connolly*, 113 U.S. 27, 31 (1884). This case reflects one of the most important purposes of the IPR program, development of national resources, and the increase of wealth and prosperity. All of these things will be affected by an interruption of foreign petroleum products, upon which the economy so heavily relies.

A zoning ordinance which restricted the drilling of wells to one per block was upheld as both a protection of owner's correlative rights in a common source of supply and as a protection of property values. *Marrs* v. *City of Oxford*, (D. Ct. Kan., 1928), 24 F. 2d 541. Citing *Barbier* v. *Connolly*, the court stated that it is sufficient to say that the police power is not limited to the protection of the health, peace and morals of the community. "It has been said to extend to acts that increase the industries of the state, develop its resources and add to its wealth and prosperity and to promote the public convenience or the general prosperity." 24 F. 2d at 546. The court acknowledged that the reason cited most often for zoning ordinances was the stabilization and preservation of property values. See also Village of Euclid v. Ambler Realty Co., 75 S. Ct. 114 for a discussion of zoning ordinances.

Again, the purpose of the proposed IPR regulations, to protect U.S. industry in the event of an oil embargo, to develop reserved resources, so as not to deplete our own, and to guarantee continued prosperity in the face of a boycott, comes within this general framework. Some may argue that a zoning ordinance protects against an imminent danger, such as a shopping center about to be built in the middle of a residential community or a liquor store next door to a church, while an Arab boycott is not an imminent occurrence, only possible. However, zoning ordinance also provide notice that such construction is not allowed, so that none is planned. Such ordinances have a preventive purpose also, which the IPR program also reflects.

Property May Be Deprived of Most Beneficial Use

If a statute, regulation or ordinance is determined by the court to be a valid exercise of the state's police power, the fact that it deprives property of its most beneficial use does not render the statue unconstitutional. Goldblatt v. Hempstead, 82 S. Ct. 987 (1962). "A prohibition simply upon the use of property for purposes that are declared, by valid legislation to be injurious to health, morals, or safety of the community, cannot, in any just sense be deemed a taking or appropriation of property for the public benefity. Such legislation does not distrub the owner in the control or use of property for lawful purposes nor restric his right to dispose of it, but is only a declaration by state that its use by any one for certain forbidden purposes, is prejudical to the public interests." Mugler v. Kansas, 123 U.S. at 668-669.

The Court has also upheld a Los Angeles ordinance prohibiting the operation of a brickyard in an area which had become residential over a number of years. The ordinance did not prohibit the plaintiff from continuing to remove the clay from the ground and transporting it to another site for manufacture into bricks, although, this was according to the owner economically infeasible.

The Court sustained the ordinance because it was narrowly drawn to prohibit the manufacture of bricks in a residential community, a business which produced fumes, smoke and soot, impacting upon the health and comfort of the community. While this was the most beneficial use of the property, it was not the only possible one.

Similarly, while it is more beneficial to the oil companies to place the oil in commerce the companies will still be able to use the petroleum since they will never actually lose title to it or, if sold, the market value of the oil. They might be able to use its value as security for some type of loan, with the understanding that it is in storage, or they could sell or trade title to it to another company. Imposition of the storage requiremetns does not necessarily deny all uses of the petroleum to the oil companies, only the most beneficial use, and full use will be returned at the end of the program.

Emergency and War Powers

Exercise of the federal government's police powers, war powers or emergency powers in cases of imminent peril to the general welfare does not fall into the fifth amendment limitation, although taking of private property often results. This view is well supported in legal history. *Miller* v. *United States*, 11 Walt. 268, 20 L. Ed. 135; *Juargua Iron Co.*, Ltd. v. United States, 212 U.S. 297, 29 S. Ct. 385, 53 L. Ed. 520; United States v. Chemical Foundation Inc., 272 U.S. 1, 47 S. Ct. 1, 71 L. Ed. 131; Cemnia Commercial Company v. United States, 261 U.S. 502, 43 S. Ct. 437, 67 L. Ed. 773.

In Franco-Italian Packing Co. v. United States, (U.S. Court of Claims, 1955) 128 F. Supp. 408, the Court upheld the actions of Navy officers immediately after Pearl Harbor in interrupting the fishing operations of certain tuna boats, directing them into port, and then finally ordering them to leave the Pacific Sea Frontier. These actions were "clearly emergency actions demanded by the circumstances, taken in the national defense, and were completely unrelated to a direct appropriation of plaintiff's property for public use." 128 F. Supp. at 414.

United States v. Caltex, 73 S. Ct. 200 (1952) involved proceeding to recover compensation for the demolition of oil companies' terminal facilities in Manila at the time of the Japanese attack. The holding of that case adopted dictum of an earlier case, United States v. Pacific R. Co., 7 S. Ct. 490 (1887) concerning the destruction of certain bridges by the Union Army to impede the advance of the Confederate Army during the civil war. "The safety of the state in such cases overrides all considerations of private loss." 7 S. Ct. at 493.

It should be noted that the Court in Caltex distinugishes these situations from tow other cases, Mitchell v. Harmony, 1852, 13 How. 115 and United States v. Russel, 1871, 13 Wall. 623, because the Army's purposes in Caltex was limited to the sole objective of destroying property of strategic value to prevent the enemy from using it. In the other two cases, the military impressed certain equipment for subsequent use by the Army. The Court in Caltex stated that the language in the earlier two cases is far broader than the holdings and that they are not precedent to establish a compensable taking in the Caltex case. Thus, the folllliwng language, while noted, should be read with that limitation in mind. "Extraordinatry an unforseen occurrences arise, however, beyond all doubt in cases of extreme necessity in time of war or immediate and impending public danger, in which private property may be impressed into the public service, or maybe seized and appropriated to the public use, or may even be destroyed without the consent of the owner. . . Exigencies of this kind do arise in time of war or impending public danger but it is the emergency. . .that gives the right and it is clear that the emergency must be shown to exist before the taking can be justified. Such a justification may be shown, and when shown the rule is well settled that the officer taking private property for such a purpsoe, if the emergency is fully proved, is not a trespasser, and that the government is bound to make full compensation to the owner." U.S. v. Russell, 13 Wall. 623, 627, 628 (1871).

In U.S. v. Central Eureka Mine Co., 78 S. Ct. 1097, 1104 (1958), the Court recognized that traditionally, a government regulation can so diminish the value of property so as to constitute a taking, United States v. Causby, 66 S. Ct. 1062 (1946), but that the merefact that a reputation deprives the property owner of the most justifiable use of his property is not necessarily enough to establish the owner's right to compensation. Furthermore, in the context of war, the Court is "reluctant to find that degree of regulation which, without saying so, requires compensation to be paid for resulting losses of income. . . War, particularly in modern times, demands the strict regulation of nearly all resources. It makes demands which would otherwise be insufferable."

In these cases, the Court recognizes that this is an emergency situation; the Japanese are entering Manila; the Confederate Army may cross the bridge; Pearl Harbor has just been bombed. The actions are directly related to a particular aspect of the immediate emergency.

However, Juragua Iron Co., Ltd. v. United States, 29 S. Ct. 385 (19) entailed the destruction of a building in

Cuba, believed to contain infectious germs capable of spreading yellow fever among U.S. troops fighting in the Spanish American War. This case is significantly different from the above cases since it is more closely related to preparation for an emergency than a response to an actual emergency. The building was blown up because it *might* spread germs. This was held to be a non-compensible taking as a legitimate exercise of the nations war and police powers. Similarly, the IPR program requires that companies store oil without reimbursement because of the strong possibility of an interruption of foreign oil imports. Like *Juragua*, which sought to avert the disaster of incapacitated U.S. troops in a war zone, the IPR is seeking to avert the disasterous effects of supply disruption.

→IPR file

Department of Energy
Washington, D.C. 20461

July 26, 1978

MEMORANDUM FOR JOHN VAN DER VOORT
SPRO

FROM: ROBERT C. GODWIN, JR.
Acting Assistant General Counsel
International Trade & Emergency Preparedness

SUBJECT: Industrial Petroleum Reserve

The following are our comments on potential legal and constitutional questions presented by the options Report titled, "Progress Report No. 1: Study of Mandatory IPR Options," produced for SPRO by Evaluation Research Corporation (ERC).

By way of preface, it may be helpful to reiterate a pervasive constitutional concern with IPR. This concern is whether its implementation can be tailored in such a way as to maximize the prospect that it would be characterized by the courts as a valid exercise of the police power (to protect the national safety and general welfare, to develop natural resources, health and prosperity and to take preventive actions in emergencies) and to minimize the prospect that any "taking" of private property involved would be characterized as an exercise of the power of "eminent domain", requiring compensation. If the former characterization is upheld, compensation is not required, even if a "taking" occurs. The "taking" must, however, occur in the course of "reasonable and necessary" means 1/ of exercising the police power, and the costs or "taking" imposed upon individuals "must bear a reasonable relation to the evils to be eradicated or the advantages to be secured." 2/ Pursuant to this concern, OGC has previously expressed preference for an IPR system that maximizes the extent to which the contributor (importer or refiner) maintains control over oil it provides for IPR. ERC demonstrates its awareness of this concern in its options Report (e.g., p. 9). This constitutional concern influences several of our specific comments on the options Report.

1/ Lawton v. Steele, 152 U.S. 133, 14 S.Ct. 499 (1894).

2/ Nashville C. & St. L. Ry. v. Walters, 294 U.S. 405, 429, 55 S.Ct. 487, 494-5 (1935).

Our comments are as follows:

1. Several preferred options, broadly categorized as "E3", require that companies segregate IPR oil from their own inventories, although these options propose allowing companies to "pool" their IPR oil. Previous OGC advice expressed a preference for allowing companies to amalgamate IPR oil with their own inventories on the grounds that this would give companies greater control of their own oil and hence reduce the risk of a court finding a compensable "taking" had occurred.

While such "E3" options do increase this constitutional risk, they would not, we believe, necessarily entail an adverse finding in litigation, especially if the administrative and other reasons cited in the Report for the preferred options can be firmly supported on factual grounds and if there are other indicia of control retained over the oil. We note that the courts have tended to pay considerable deference to the exercise by DOE of discretion granted it under the EPAA and EPCA.

2. Partly to meet the above constitutional concern, the Report prefers an option (H3) allowing companies to draw down IPR reserves for their own needs when there is no supply emergency. It apparently is envisaged (p. 9) that this right would be subject to certain rules as to drawdown and "re-fill scheduling" or that the USG would be given a veto power in each case. The IPR would, in effect, be an exchange of last resort. Whichever mechanism for controlling this suggested drawndown right is adopted, it will have to be structured to meet both difficulties identified in the Report, viz., that the IPR might, in effect, replace emergency inventory reserves already kept for commercial reasons and that wide use of the non-emergency drawdown right just prior to a major supply interruption might jeopardize the effectiveness of the SPR program. Failure to so structure the drawdown right might run counter to the general SPR policies of §151(a). Subject to this policy, however, discretion to permit non-emergency IPR drawdowns, and prescribe rules therefor, is specifically granted to the Secretary in §161(f).

3. The entitlements program, as presently structured, would not accommodate the equalization of refiners' or non-refiners' crude oil costs as a means of financing

the IPR, as contemplated in the Report (p. 10). Modifications in the entitlements program would be required to achieve this result with respect to the IPR.

4. The options Report suggests (p. 10) levying on companies fees based on national average per barrel costs for storing IPR oil, in order to equalize the burden of IPR storage costs among such companies. DOE properly may charge a storage fee for oil voluntarily stored in USG facilities. Hence, a system whereby firms might opt to pay the USG a reasonable fee for storing their IPR oil obligation in USG facilities, rather than in their own, could be defended. However, there is no authority in §§156 or 159 of EPCA for extending such system to impose a fee on companies to reimburse other companies who might store their oil. Because the statute does not address this question, new legislation probably would be required to establish such authority.

5. The options Report contemplates (p. 4) the possibility of treating "producers" as a discrete class subject to an IPR program. It should be recognized that DOE's IPR authority is limited, under EPCA §§156 and 159(f)(H), to importers and refiners, and excludes producers as such.

6. The paper considers (p. 6) the possibility of requiring that IPR oil be stored in PADs I-III. If storage in Government-owned facilities were required, as §159(f)(I) indicates it may be, this could be effectuated by locating the Government's facilities in those areas, though to the extent that this reduced IPR firms' control over their oil, the risk would be aggravated that the courts would find that this constituted a compensable "taking". However, independent of the constitutional question, a litigant might challenge whether DOE has authority under the EPCA to require that IPR firms locate their own storage facilities in PADs I-III. While there is no explicit authority in §156 for imposing such requirement, it might be justified as a reasonable means of implementing §156.

7. Proposals limiting storage obligations to importers or refiners in PADs I-III only would present serious legal problems.

8. There is no specific proscription in the EPCA on DOE's requiring that companies use USG - operated storage facilities; indeed, it is expressly authorized under §156(f)(I). Such requirement should be readily defensible unless, perhaps, a company can establish that, because it has suitable segregated storage facilities available, imposition of the requirement in its case would be patently unreasonable. Such a showing by an individual might justify a grant of review or exemption by DOE as envisaged in §156(c), rather than present a challenge to the requirement itself.

9. The options Report contemplates (p. 11) the concept of chartering a private entity, rather than the USG, to act as an IPR storage organizer. What appears to be envisaged is that such entity would act independently, in a form analogous to a public utility, in pursuing this function. The Report speaks of a "privatized" IPR enterprise. Such an entity probably could not be established without new legislation. The Government Corporation Control Act of 1945 proscribes generally the creation, organization or acquisition by the USG of a corporation to act as an agency or instrumentality of the United States, unless specifically authorized by an Act of Congress.3/ While the EPCA give DOE wide discretion in implementing the IPR, it contains no such specific authorization.

It may be possible, however, to utilize the services of a private sector contractor to assist USG in the performance of certain of its IPR functions; but the permissability of such utilization would have to be evaluated on its merits. Such evaluation would require a more detailed submission as to what is proposed.

3/ 31 U.S.C.A. §869(a).

SPR File → Industrial Petroleum Reserve

Department of Energy
Washington, D.C. 20461

August 18, 1978

MEMORANDUM FOR DAVID BLOOM, P&E
KEN GLOZER, OMB
HARALD LEUBA, ERC
JOHN VANDER VOORT, SPRO

FROM: ROBERT C. GOODWIN, JR.
ASSISTANT GENERAL COUNSEL FOR INTERNATIONAL TRADE AND EMERGENCY PREPAREDNESS

SUBJECT: LEGAL QUESTIONS RAISED BY ERC "IPR OPTION SUMMARY" OF 8/2/78 - LEGALITY OF PROPOSED OPTIONS WITHIN EPCA/EPAA FRAMEWORK

This memorandum addresses questions raised by you at the meeting of 8/2/78 concerning the IPR. It replaces our previous preliminary memorandum of 8/9/78 on the same subject (but titled, additionally, "Preliminary Views") and should be substituted therefor. You asked us to examine the legality of certain options under the EPCA and EPAA, and to defer for later examination, when a more specific set of options is developed, constitutional questions and the conformity of these options to the regulations promulgated pursuant to EPCA and EPAA. However, we will make note of certain obvious constitutional concerns with the questions you have raised. The storage option referring to the Langdon proposal is not addressed herein; the Langdon proposal will be considered in its entirety in a separate memorandum.

1. Permissible Storage Options The first three options - company tankage, pooled storage and a centralized facility operated by a third party - are all permissible within the EPCA/EPAA framework. Section 159(f)(I) grants DOE broad discretion to specify IPR storage in USG 1/ or privately owned facilities, as long as the latter are subject to

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1/ As noted in our previous advice, however, mandating storage of oil in USG facilities reduces the company's control of such oil and hence increases the chances of a court finding that a compensable "taking" has occurred.

audit by the USG. Clearly, that discretion would include allowing companies to choose among certain options. There is nothing in the EPAA to disturb this conclusion.

As noted in our previous advice, 2/ the fourth option - levying fees to be paid to SPRO as a "share" in SPR - is not specifically authorized by the EPCA and hence is not permissible under the general revenue law which require specific statutory authority for the imposition of such fees. 3/ Indeed, the imposition of such a fee might be held to be an unconstitutional tax in violation of Art. 1, §8, cl. 8 of the Constitution if the court feels it exceeds a reasonable recompense for any "benefit" conferred upon the company. 4/

However, fees imposed which do represent a reasonable recompense for services rendered by USG are generally valid. 5/ The option of the USG charging rental for the lease of a salt dome, for instance, would appear defensible both constitutionally and under EPCA, where the language of §156(b) and §159(f)(I) appear to contemplate such an arrangement.

2/ Memorandum of 7/26/78 to John Vander voort from Robert C. Goodwin, Jr. concerning the SPR, Item 4.

3/ The Courts have construed the power of Federal agencies to levy fees very narrowly. Only Congress may impose taxes under the Constitution. National Cable Television Association, Inc. 415 U.S. 336, 94 S. Ct. 1146, 39 L.Ed. 2d 370 (1974). The only circumstances in which the courts have recognized the rights of Federal agencies to improve fees and when such fees paid for specific benefits rendered to the recipient by the USG and are reasonably commensurate with the "value to the recipient" in accordance with the Independent Offices Appropriations Act of 1952, 31 U.S.C.A. § 483, National Cable Television, op. cit. 341-343; and when the statute specifically authorizes the imposition of fees or penalties as a means of enforcing a regulation. Moon v. Freeman, 379 F. 2d 382 (9 Circ. 1967); Rodgers v. U.S., 138 F. 2d 992 (6 Cir. 1943). Outside these parameters, the financial imposition will be treated as a tax which Federal agencies may not levy under the Constitution.

4/ National Cable Television Association, Inc. v. U.S., op cit.; Federal Power Commission v. New England Power Corp., 415 U.S. 345, 94 S.Ct. 1151, 39 L. Ed. 2d 383, (1974).

5/ Id.

2. Financing Options Self-provided or self-financed tankage and oil clearly are permissible options under EPCA. Bank financing from the private sector also is permissible. Aside from potential antitrust problems 6/, there appears to be no barrier in EPCA or EPAA to the establishment by companies of a private sector entity to manage the financing of oil storage, whether such entity is an equity company or a voluntary association of the companies concerned.

6/ Such antitrust questions are properly the concern of the counsel to the companies concerned, and could not be answered definitively until the exact form of entity proposed and its market environment is examined by antitrust counsel.

In response to your inquiry, however, we do note in general terms that a joint venture may be held to foreclose actual or potential competition among the parent companies and their progeny in violation of Section 7 of the Clayton Act U.S. v. Penn-Olin Chemical Co., 378 U.S. 158 (1964). However, cases proscribing joint ventures on antitrust grounds are few and of relatively recent vintage. Given the objectives of the proposed joint venture, corporate counsel may well conclude that it presents no serious antitrust risks. If access to the joint venture or ventures were made available to all companies with IPR obligations, whatever antitrust risks are presented should be reduced and the objectives of the EPCA and EPAA directed against inequitable economic impacts and market distortions more readily met.

If the proposed entity were to take the form of a trade association rather than a joint venture, it might still run afoul of Section 1 of the Sherman Act, which generally proscribes combinations in restraint of trade. Certain trade association activities, such as discussions of price, are generally risky. Again, the companies' antitrust counsel would have to address these questions in the context of the particular arrangement and its circumstances.

Neither antitrust risk appears so severe as to preclude further consideration of this option by the USG at this point. If the risks are serious, they will be handled by the companies' antitrust counsel at the time of formation, or earlier. Some measure of insulation from antitrust litigation might be obtained by such counsel in the form of advance DOJ clearance of the proposed entity by use of the Business Review Letter procedure.

The suggestion that the USG play a role in the entity is more vexed. A USG loan guarantee would not be possible without specific statutory authority, 7/ of which there is none in EPCA or the EPAA. Furthermore, the USG may not, without specific Congressional authority, help to create or organize such entity if it is in any way to serve as an agent or instrumentality of the United States; 8/ again, no such authority exists in EPCA or the EPAA.

Certain types of USG involvement such as advice and consultation, are permissible; others are not, e.g., advertising on the entity's behalf or its use of USG personnel, facilities equipment or material. Other potential involvement, such as a USG presence on the Board of Directors, would require more detailed examination before we could opine as to its legality.

3. Cost Recovery - Legality of Proposed Means The EPCA and EPAA give DOE broad discretion in establishing the IPR and in imposing a system of price controls. The EPAA contains more specific mandates as to cost pass-through to consumers. The proposed option envisages that the cost burden of financing and storing IPR oil will be imposed on all importers and refiners, presumably on an equitable pro rata basis within the 3% limit mandated in EPCA §156(b). Such an arrangement is clearly contemplated in §156 and should present no problem. In meeting the required storage obligation, each refiner and importer would incur its own cost in the market place. However, the notion that certain opportunities will be provided for importers or refiners to place an effective ceiling on their cost burden (through the provision of USG storage and other devices), also appears unobjectionable under §156 and §159. Moreover, such "cost recovery" arrangements appear to serve several of the objectives of both the EPCA and EPAA. These objectives include the direction to "avoid inequitable economic impacts" (EPCA §156(c)), to minimize "economic distortion, inflexibility and unnecessary interference with market mechanisms" (EPAA §4(b)(1)(I) and to preserve an "economically sound and competitive petroleum industry" 9/ (EPAA §4(b)(1)(D), and EPCA §156(c)). The

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7/ See fn. 3, Supra.

8/ Government Corporation Control Act of 1945, 31 U.S.C.A. §869(a).

9/ "Preserving competition" in this context almost certainly means, inter alia, preserving the ability of the small company to continue to compete effectively and not be unduly harmed by adverse impacts of the regulation (even if proportionately shared). This "bias" is certainly not out of line with that of the Supreme Court in the antitrust area.

cost "ceilings" are further in conformity with the EPAA/EPCA framework if they are designed to protect the small refiner, or any refiner, from undue hardship.

However, the proposed option does carry implications for several of the major regulations promulgated by DOE pursuant to EPCA and EPAA. We understand you have consulted ERA as to how ERA would foresee some of these options fitting into the regulatory framework.

4. Accessibility - Drawdown Capacity The notion of mandating a certain drawdown rate capability in storage requirements would appear to be a reasonable exercise of DOE's statutory authority in EPCA §§156 and 159(f)(I). These sections give DOE wide discretion to impose storage requirements - "on such reasonable terms as the Secretary may specify".

The mandate in §156(b) that the storage be in "readily available inventories" is also helpful to this exercise of discretion. This term is defined in §152(5) as stocks "which can be distributed or used without affecting the ability of the importer or refiner to operate at normal capacity." Hence, they could be required to maintain IPR storage in such manner that the mandated drawdown rate not disturb their normal operations and so not weaken their ability to serve the market effectively in times of crisis. This exercise of discretion would, however, be subject to the inherent limitation that it not impose unreasonable burdens on refiners or importers. The mechanism in §156(c) for granting relief in "special hardship" cases provides an avenue for handling "unreasonable" burdens imposed and, if used effectively, could reduce considerably challenges to DOE's exercise of discretion under §156. This comment applies generally to situations under §156 where DOE purports to exercise the broad discretion granted it.

5. Geographical Location of Storage The option proposed - that companies have the choice of storing in their own tanks or in USG or private sector facilities located in regions specified by the USG - appears defensible under EPCA. The notion of the USG specifying which of its own facilities may be used clearly is legal. Specification of the broad location or area within which other private sector facilities used must be located also appears defensible as a reasonable exercise of DOE's authority inherent in EPCA. The fact that

the company has the choice of using its own facilities, wherever located, or those of other parties located in specified areas is helpful in establishing the reasonableness of this exercise of discretion.

6. How Levied - Bond in Lieu of Storage The USG may be able legitimately to purchase oil for IPR on behalf of companies. However, in our opinion, a bond in lieu of the storage requirement, representing a promise to pay or, perhaps, furnish oil in the future, is not authorized by the EPCA. 10/ While EPCA grants considerable discretion to DOE, that discretion is to be directed towards implementing actual storage requirements for the SPR. A bond in lieu of storage is not actual oil storage. Moreover, use of a bond would not be consistent with the basic emergency preparedness objective of the SPR, of which the IPR is part.

7. Enforcement Sections 524 and 525 of the EPCA prescribe comprehensive and stringent penalties for violations of SPR provisions. Any violations of, inter alia, the SPR or IPR provisions of EPCA, or of any rule, regulation or order issued pursuant thereto, may carry up to $5000 civil penalty for each such violation, $10,000 for each willful violation. Willful violations involving sale or distribution of products or commodities, after a civil penalty is imposed with respect thereto, may lead to aggravated penalties of up to $50,000, 6 months imprisonment, or both. The USG also has the authority to seek an injunction against potential violations; and aggrieved private parties may seek declaratory or injunctive relief against the USG for wrongful application of certain provisions.

Violations of EPAA regulations promulgated pursuant to the President's mandatory allocation authority in §4(a), or of other orders in the EPAA, are also subject to stringent civil penalties for each violation ($20,000 in the case of crude oil-related activities; $10,000 where distribution of residual oil or refined petroleum products is concerned; $2,500 in retail distribution or other cases). Even more severe penalties (generally double the above penalties or 1 year's imprisonment) are prescribed for willful violations in these situations. EPAA §5(3).

Inherent in the power of reasonable regulation, and the enforcement thereof, is the ability of DOE to obtain access to company records, inspect their operations, and other reasonable incidents of effective monitoring and enforcement. Further authority for these incidents of effective enforcement exists in Section 13 of the FEA Act.

10/ See fn. 3, supra.

→ MBH
copy → IPR file

Department of Energy
Washington, D.C. 20461

September 22, 1978

MEMORANDUM FOR JOHN VANDER VOORT
CHIEF OF THE INTERRUPTION BRANCH
STRATEGIC PETROLEUM RESERVE

FROM: ROBERT C. GOODWIN, JR. R.C.G.
ACTING ASSISTANT GENERAL COUNSEL
INTERNATIONAL TRADE & EMERGENCY PREPAREDNESS

SUBJECT: LITIGATION CHALLENGING IMPLEMENTATION OF IPR PROGRAM AND PROBABLE DELAYS OCCASIONED THEREBY

Introduction:

You have asked us to identify the most probable types of litigation challenge from affected refiners or importers to implementation of the IPR; and to estimate what sorts of delays in implementation, if any, might be occasioned by such challenges.

You have asked us, further, to act under the assumption that affected refiners and importers will vigorously oppose the IPR and use whatever legal means are available to challenge its implementation, and that some form of litigation is therefore very probable.

Discussion:

Litigation Risk

An assessment of this nature is highly speculative without knowing the specifics of the program, what exactly is challenged, and in what context the challenge arises. To limit somewhat the speculative nature of this exercise, we are also assuming herein that the validity of the program would, in the final analysis, be sustained by the courts in each of the areas of possible challenge identified.

We believe that a legal challenge in any one of the following areas might be anticipated:

1. Constitutional.

The most probable constitutional challenge would be that the implementation of the IPR would present a "taking" of the emburdened companies' property (e.g. the oil stored or storage space) for public use, requiring "fair and just compensation" under the Fifth Amendment of the U.S. Constitution.

If the program is designed to ensure that whatever "taking" occurs is a reasonable exercise of the police power in regulating property for the public benefit, as opposed to an outright exercise of the power of eminent domain, the risk of an unfavorable ruling on this question could be minimized. We have previously advised you as to what this distinction might mean with respect to specific aspects of some of the options discussed.

If an effort is made to levy fees on companies as part of or in lieu of their IPR obligations, such fees might also face challenge as a tax not authorized by Congress and hence in violation of Art. 1, §8, cl. 1 of the Constitution.

2. Invalid Regulation under the EPCA.

Some companies may charge that the proposed IPR program is not a valid exercise of the authority granted DOE under §156 of the EPCA. If, for instance, all companies are required to store an equal percentage of their throughput or product imports, small refiners or importers that are especially adversely affected by the obligation may charge that the program does not meet the mandate in §156(c) to implement the program "in a manner which is appropriate to the maintenance of an economically sound and competitive petroleum industry". If, on the other hand, "variable obligations" are imposed, with either total exemption or smaller percentages imposed on small refiners or importers, the larger companies may charge that DOE has failed to avoid "inequitable economic impacts on refiners or importers" as required in §156(c) or, perhaps, more generally that the program is simply unfair, irrational and therefore an abuse of DOE's discretion.

3. Environmental Laws

The program would have to comply with applicable environmental regulations, including those under:

(a) The National Environmental Policy Act (NEPA)

(b) The Clean Air Act

(c) The Clean Water Act

(d) The Coastal Zone Management Act.

In this connection, it is premature to determine the timing, nature and scope of the environmental impact statement (EIS) required to be prepared pursuant to §102(2)(C) of NEPA or the nature and timing of the permits that might have to be obtained by the affected refiners and importers, with respect to storage in their own facilities, from the Environmental Protection Agency (EPA), the Army Corps of Engineers and the appropriate State authorities under the Clean Air and Clean Water Acts and the Coastal Zone Management Act.

Possible Delays Occasioned by Litigation

(a) Constitutional and EPCA Challenges:

Our estimate is that litigation challenges based on constitutional grounds or on the alleged invalidity of the proposed program under the EPCA (areas 1 and 2 identified above) should be disposed of within nine months to a year. This estimate is based upon the experience of our regulatory litigators in defending other DOE regulations against challenges. More pertinent is the estimate that the filing of such suits need not seriously delay implementation of the IPR program unless the parties suing are able to persuade the court to enjoin implementation pending the outcome of the case. Such imposition of a preliminary injunction is not probable given that the party suing has the burden of establishing both the likelihood of success in the outcome of the case, and irreparable injury to itself that could not be cured by the damages or other relief it is seeking. A court is more likely to issue an injunction in cases where the issue involves something other than just money. With the exception of possible environmental claims, it is likely that most litigation disputes over the IPR would probably involve only money damages and hence would not, in the eyes of most courts, justify enjoining the program pending resolution of the issues in dispute. Furthermore, even if a preliminary injunction were imposed by a district court, DOE could take an immediate appeal against it.

However, it cannot be stated with certainty that no substantial delays would be involved without knowing the exact posture of each case. Furthermore, the mere fact of litigation may occasion some administrative delays and would, of course, involve DOE in additional legal work. This is a problem inherent in DOE's regulatory function. We are presently involved in about 250 law suits challenging our regulations.

If companies suing were to appeal adverse district court rulings, the litigation would take longer to dispose of. Here, however, the prospects of the program being enjoined are even less.

Of course, should DOE receive an adverse ruling on the substance of a constitutional challenge or legal challenge based on the EPCA provisions, the program may have to be suspended until the illegal aspect is corrected or, perhaps, even terminated. However, an adverse district court ruling could, of course, be appealed by DOE and district courts will usually stay enforcement of an adverse decision until the agency has had an opportunity to have an appeal heard.

(b) Environmental Laws:

The potential for delay in the environmental area (area 3 identified above) is different and probably more serious. While it is, as stated, premature to assess the exact timing of preparing an EIS or obtaining necessary permits under the Clean Water and Clean Air Acts, it can be noted that failure to comply with applicable requirements could seriously delay implementation of the program. Potential delays are of two types.

Firstly, parties dissatified with the EIS might sue in the Federal district court. Given the liberal attitude of most courts towards standing to sue in this area, potential plaintiffs could well include affected importers and refiners. Here, unlike the above-discussed constitutional and EPCA challenges, the potential for the plaintiffs enjoining implementation of the program are considerable if the EIS does not comply with NEPA; indeed, many cases in this area are effectively resolved at the preliminary injunction stage. Because of the expedited procedures for hearing and deciding preliminary injunction motions, the matter is likely to be resolved somewhat quickly and rapid appeals, if permitted, could be taken against adverse results. The prospects for delaying implementation during this period are limited; the court might grant a ten-day temporary restraining order on implementation. Should DOE successfully resist the injunction, the program could continue unabated. However, should the plaintiff prevail, the court could enjoin the entire program, implementation of which would have to be suspended until the NEPA violation was corrected; it might then take several hearings to satisfy a court as to compliance. However, it must be noted that the basis for challenge under NEPA is that the EIS has not been adequately or properly prepared and utilized in the decision-making process, not that the program is environmentally unsound. Furthermore, the courts have not always granted injunctions, even where a violation of NEPA is found; more often they have required the agency to rectify the EIS within a certain period without stopping the program. This is more likely when they are asked to enjoin an entire program, such as the IPR, as opposed to a specific project, such as a dam.

Secondly, once the program is in force, there is considerable potential for delay in construction of the actual physical storage facilities in those cases where permits must be obtained under the Clean Air and Clean Water Acts for new or substantially modified facilities from the EPA, the Army Corps of Engineers, and the States. With respect to IPR storage in SPR facilities, the prospects for delay should not be substantially different from those of the SPR itself.

cc: David Bloom, P&E

RESPONSE TO ADDITIONAL QUESTIONS FOR THE RECORD
POSED BY SENATOR WALLOP
HEARING ON MARCH 11, 1991 (Titles VII and VIII of S. 341)
RECEIVED FROM IPAA, Denise Bode

QUESTIONS FOR INDUSTRY WITNESSES (PANEL II)

1. Would you agree that many of today's energy problems stem from reliance on an international market-place where energy prices have no relationship to the costs of production or the full costs of maintaining access to those supplies?

IPAA agrees generally. Yet we hasten to point out that the term "market-place" might well mask the true nature of world crude oil commerce. Afterall, the vast majority of world oil supplies are controlled by governments, not by private sector enterprises, and traditional commercial factors alone do not drive oil production and marketing decisions by state-owned oil companies.

Nonetheless, it is important to point out that "cost of production" does have a bearing on the ability of OPEC nations to dominate world oil commerce. Specifically, OPEC nations have a cost of production considerably below that of U.S. private-sector firms. Constrained primarily by financial obligations which must be met by oil revenues, OPEC nations are able to manipulate production, supplies and, ultimately, prices of oil for purposes that may not be consistent with the U.S. energy and environmental policy goals which underly proposed national energy security legislation.

IPAA believes that a world oil price collapse, as experienced in the late 1980s, will do serious harm to the U.S. oil and natural gas resource base, hitting first and hardest U.S. stripper well production. The impacts of cheap oil will also be harmful to initiatives for conservation and alternative fuels. In addition, IPAA believes there is a significant probability that oil prices will collapse when Kuwaiti and Iraqi oil production returns to the world market, unless there is an OPEC agreement to limit production and to accept the proposition that oil will have a decreasing share of world energy consumption.

Finally, IPAA believes that the costs associated with dependence on foreign imports (i.e., military expenditures to assure access to foreign supplies, increased environmental risks from inceased tanker traffic, and losses to national wealth and economic activity derived from mineral extraction, balance of payments costs, and others) are not reflected in the price at the pump.

2. Do you agree that the United States must find the means to stimulate development of competitive supplies by assuring sufficient stability in domestic energy prices that investments can be made in the development of domestic alternatives?

IPAA believes domestic oil price stability is the most important "missing element" in current U.S. energy policy and the administration's proposed national energy strategy. While changes in tax policy (such as elimination of tax preference treatment for intangible drilling costs and percentage depletion under the alternative minimum tax) would help improve the economics of domestic oil and natural gas exploration and production, tax changes alone are not sufficient to bring stability.

The achievement of price stability in the petroleum industry would have the side-effect of encouraging the development of alternative energy sources. However, fossil fuels -- primarily oil and natural gas -- are the only domestic energy sources that can reasonably be produced commercially at current price levels. Oil prices would have to rise to an equivalent of at least $30 per barrel for most alternative energy source to become feasible in the United States.

What mechanism would you propose to accomplish this objective?

IPAA supports the establishment of a minimum security price for oil and petroleum products imported into the U.S., as proposed in S. 217 and other legislation. IPAA is concerned that the adoption of a national energy policy designed to decrease reliance on oil will actually work to decrease domestic production (not oil imports) unless a minimum security price is also part of that energy policy.

3. As you are aware, S. 341 contains a provision which would establish a price differential between domestic and imported crude oil and petroleum products. This is accomplished by requiring that approximately 9 percent of crude oil and petroleum product imports, or the equivalent, be furnished to the Federal government for use in both filling the Stategic Petroleum Reserve and meeting the fuel requirements of the Department of Defense.

a. Would you agree that this requirement is in effect a surcharge on the importation of crude oil and petroleum products?

Yes.

b. What mechanism would you propose to fund expansion of the Strategic Petroleum Reserve under the present Federal budgetary contraints?

If there is a need to expand the strategic petroleum reserve, the existing method of funding is preferable to new special taxes. The degree of need for a strategic petroleum reserve is a function of the degree of U.S. dependence on foreign oil. Oil importers, in the event of a supply disruption, are the very people who will seek a drawdown of strategic reserves. Others may also desire a drawdown to ameliorate oil prices by increasing supplies, but it will be primarily those firms that need the commodity that will rely on Federal government supplies. It is reasonable to expect importers to fund the insurance policy they will need. Any fee on imported oil for such purpose will provide an increased incentive for domestic production, decreasing to some extent the need for strategic reserves.

PMAA
PETROLEUM MARKETERS ASSOCIATION OF AMERICA
1120 VERMONT AVE., NW • SUITE 1120 • WASHINGTON, DC 20005 • (202) [illegible]

March 28, 1991

Senator Malcolm Wallop
Ranking Republican Member
Committee on Energy and National Resources
United States Senate
SR-237 RSOB
Washington, D.C. 20510-5001

Dear Senator Wallop:

Please consider this the response to the questions you raised in your March 13th letter to John Arnold on energy policy. You posed these questions as a follow-up to the March 11 hearing.

> (1) Would you agree that many of today's energy problems stem from reliance on an international market-place where energy prices have no relationship to the costs of production or the full costs of maintaining access to those supplies?

PMAA believes that a complex interaction between costs, supply and demand determine prices in world energy markets. History has shown that markets are far better at allocating scarce resources than are governments. U.S. energy policy should not interfere with energy market pricing, but should, on the other hand, encourage the creation of additional production worldwide to limit the control that any producer country or group of producer countries can exert in international markets.

> (2) Do you agree that the United States must find the means to stimulate development of competitive supplies by assuring sufficient stability in domestic energy prices that investments can be made in the development of domestic alternatives? What mechanism would you propose to accomplish this objective?

Yes and No. PMAA has always supported a strong domestic energy industry. However, we believe there are less economically destructive and disruptive ways than artificial energy pricing mechanisms like oil import fees to induce exploration and production of domestic energy sources. For example, the federal and state governments can encourage domestic oil activity by reducing severance taxes on crude oil, by extending the oil depletion allowance, and through increasing the intangible drilling credits. In addition, we could adopt a system similar to the one the United Kingdom uses in the North Sea. Under this system a well's production is not taxed until all the exploration and development costs have been recovered by the company. Currently the domestic oil industry carries the heaviest tax burdens of any industry and recent changes in the tax law due to the enactment of Superfund legislation increases that burden substantially. PMAA also supports the opening of more federal lands for offshore drilling as well as the ANWR.

PMAA believes we must find a way to "stimulate domestic energy sources" but not at the expense of the American economy.

(3) As you are aware, S. 341 contains a provision which could establish a price differential between domestic and imported crude oil and petroleum products. This is accomplished by requiring that approximately 9 percent of crude oil and petroleum product imports, or the equivalent, be furnished to the Federal Government for use in both filling the Strategic Petroleum Reserve and meeting the fuel requirements of the Department of Defense.

a. Would you agree that this requirement is in effect a surcharge on the importation of crude oil and petroleum products?

Yes. The set-aside mechanism in S. 341 acts as an import fee on crude oil and petroleum products. The level would be approximately 9 percent. The economic effect would be identical to an oil import fee. PMAA believes that this is an extremely inefficient and uneconomic mechanism for funding acquisition for the SPR or for meeting the fuel requirements of the Department of Defense as John Arnold testified at the hearing.

b. What mechanism would you propose to fund expansion of the Strategic Petroleum Reserve under the present Federal budgetary constraints?

PMAA continues to support the SPR and the notion of increasing the reserve's fill rate from its current levels. However, we believe funding a buildup of the SPR through the import set-aside program in Title VII of S. 341 is fundamentally unfair and would ultimately work against the goal of energy security.

Since all Americans benefit from a strong SPR, all Americans should bear the cost of financing it. Because PMAA understands the fiscal constraints associated with raising the SPR to a billion barrels and increasing the fill rate of the SPR from current levels, we strongly support alternative means of financing that do not unfairly discriminate among individual citizens of the Untied States.

One of the measures we support in this regard is a viable SPR oil leasing program. It is our understanding that in September of 1990 the Department of Energy (DOE) was given statutory authority to enter into contracts to store oil owned by others in the reserve. Such a program would help to fill the SPR at a minimal cost to the Federal Government. As soon as practicable, DOE should move forward with negotiations with a number of prospective suppliers to lease oil for the SPR. Now that the Persian Gulf situation has been resolved, the Middle East oil producing allies of the United States may be more willing than ever to enter into these types of agreements.

To the extent that favorable leasing arrangements cannot be negotiated with producers, petroleum should continue to be acquired for the SPR through purchases to the extent possible given federal budgetary constraints. There are more than 560,000,000 barrels of crude oil in the SPR at this time. Although expansion is important, it is not urgent that the fill rate be increased unless the increase can be implemented without economic distortion.

PMAA appreciates this additional opportunity to present its views and would be glad to provide any further information you may need.

Sincerely yours,

Phillip R. Chisholm/ag
Phillip R. Chisholm
Executive Vice President

cc: John Arnold

American Petroleum Institute
1220 L Street, Northwest
Washington, D.C. 20005
202-682-8100

Charles J. DiBona
President

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
APR - 1 1991
WASHINGTON, D.C. 20510

March 28, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, DC 20510-6150

Dear Chairman Johnston:

Enclosed are the responses to questions you raised in your March 13, 1991 letter to me.

Please let me know if we can provide you additional information.

Sincerely,

Charley DiBona

Enclosure

Responses by Charles J. DiBona, President, American Petroleum Institute, to questions from Senator Malcolm Wallop (R-WY) for the record relating to the March 11, 1991 hearing on the Strategic Petroleum Reserve, Senate Committee on Energy and Natural Resources

Question 1: Would you agree that many of today's energy problems stem from reliance on an international market-place where energy prices have no relationship to the costs of production or the full costs of maintaining access to those supplies?

Answer: The U.S. is heavily reliant on imported oil, which trades in a world market where its price -- as determined by the quantities supplied relative to demand -- is much higher than the cost of production in the major oil exporting countries. However, even if the U.S. did not rely on oil from the Middle East, where the cost of oil production is far below world prices, or on oil from other exporting areas, our economy nevertheless would be affected by events in the oil exporting nations. This is because a substantial oil supply disruption anywhere will affect oil prices in markets around the world. Thus, our economy and the economies of many other nations are vulnerable to energy shocks; they are damaged when oil prices rise sharply and helped when oil prices remain low. The most prudent federal energy policy is not to artificially raise domestic energy prices -- which would counterproductively slow our economy -- or to substitute more costly resources for imported oil, but rather to take cost-effective steps that would improve our economic performance. These include such measures as providing greater access to public lands for energy development and avoiding overly stringent environmental and other regulations that unnecessarily impede domestic energy development. A large Strategic Petroleum Reserve, which can cushion the effects of any supply disruption, is an important part of such a prudent energy policy.

Question 2: Do you agree that the United States must find the means to stimulate development of competitive supplies by assuring sufficient stability in domestic energy prices that investments can be made in the development of domestic alternatives?

What mechanism would you propose to accomplish this objective?

Answer: Since oil prices are set on world markets, we do not believe that the federal government should take special measures to assure stability of domestic energy prices. Price volatility does not necessarily reduce investment in domestic energy development, but extensive government intervention to stabilize energy prices might well discourage such investment. Rather than trying to stabilize energy prices, the federal government should encourage domestic energy investment by providing greater access to federal lands, adopting cost-effective environmental and other regulations, and implementing appropriate tax policies. If the federal government takes the proper steps, economically justified investments in domestic energy development will be made in response to market signals.

Question 3: As you are aware, S.341 contains a provision which would establish a price differential between domestic and imported crude oil and petroleum products. This is accomplished by requiring that approximately 9 percent of crude oil and petroleum product imports, or the equivalent, be furnished to the Federal government for use in both filling the Strategic Petroleum Reserve and meeting the fuel requirements of the Department of Defense.

a. Would you agree that this requirement is in effect a surcharge on the importation of crude oil and petroleum products?

b. What mechanism would you propose to fund expansion of the Strategic Petroleum Reserve under the present Federal budgetary constraints?

Answer: The proposed requirement would have many of the same effects as a surcharge on imported oil, which I discussed in my testimony. Since the Strategic Petroleum Reserve serves a general public interest -- benefitting all Americans by protecting the economy in case of an oil supply disruption -- it should be funded from general revenues. In addition, P.L.101-383, which was enacted last year, permits the government to lease oil for storage in the Strategic Petroleum Reserve. This concept offers the potential for considerable federal budget savings in the near term. Such ways of saving money on the Strategic Petroleum Reserve should be fully explored.

Appendix II—Additional Material Submitted for the Record

STATEMENT
on
THE NATIONAL ENERGY SECURITY ACT OF 1991, S. 341
for submission to the
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
for the
U.S. CHAMBER OF COMMERCE
by
Jeffrey H. Joseph[*]
March 11, 1991

The U.S. Chamber of Commerce appreciates this opportunity to express its views on Title VIII of the National Energy Security Act of 1991. All business enterprises require abundant supplies of energy at affordable prices in order to remain competitive, create jobs, and help pull the economy out of recession. Energy exploration and development on the Outer Continental Shelf (OCS) is an essential part of a balanced, effective energy policy. The Chamber supports a policy of sharing OCS lease revenues with coastal states affected by offshore oil and natural gas development. In particular, the establishment of an Impact Assistance Fund will assist development of the OCS by easing the burden on states and local governments that must provide the transportation, education, and other community services for the work force drawn to drilling regions. Providing a greater share of the financial benefits of new and existing development to coastal communities directly affected by OCS leasing activity is sound national policy and will create an incentive for states to become involved in the OCS leasing program.

THE CURRENT CRUDE OIL AND NATURAL GAS SITUATION

The Chamber is concerned about the current domestic oil supply situation. According to the U.S. Department of Energy (DOE), over the past 10 years oil has supplied approximately 42 percent of the nation's energy needs. Oil is not only a critical component of the nation's energy supply, but also is virtually the only liquid transportation fuel. The transportation sector alone consumes roughly 10 million barrels of oil each day.

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[*] Jeffrey H. Joseph is Vice President, Domestic Policy

Despite its importance to the national economy, domestic crude oil production has been allowed to fall to its present level of 7.3 million barrels per day (mb/d), a 21 percent reduction since 1973. Production fell by 0.2 mb/d in the lower-48 states last year, and by 0.1 mb/d in Alaska. The U.S. Department of Energy projects that domestic production will continue to decline into the near future, worsening a burgeoning dependence on oil imports. Our dependence on foreign oil has grown from 27 percent to more than 40 percent during the past five years; our dependence on OPEC oil alone has grown from 11.6 percent to more than 26 percent.

The Chamber is also concerned that adequate supplies of natural gas may not be available to meet growing demand. The consumption of natural gas, which currently provides 24 percent of the nation's energy demand, rose from 16.2 trillion cubic feet (tcf) in 1986 to 18.9 tcf in 1989. Demand is projected to rise in future years due to the ozone nonattainment, acid rain, and alternate fuels provisions of the recently passed Clean Air Act.

THE BENEFITS OF OCS PRODUCTION

Since 1954, OCS production has exceeded 8.5 billion barrels of crude oil and condensate and 88 tcf of natural gas. In 1990 alone, more than 3200 offshore platforms produced an average of 836,000 barrels of crude oil and 11.5 billion cubic feet of natural gas daily, or 11 percent of the oil and 25 percent of the natural gas produced in the United States. In addition, the OCS accounts for a significant portion of existing U.S. oil and gas reserves; one-third of the estimated undiscovered, recoverable reserves in the United States are in the OCS.

The benefits of the development of this vast resource potential are significant, as indicated below.

- OCS development will reduce the risk of oil spills by reducing the need for imported oil. Roughly 95 percent of the oil from the OCS comes onshore by pipeline, not tanker. Since current federal offshore regulations went into effect more than 15 years ago, less than 0.001 percent of the oil produced from the OCS has been spilled.

- OCS development will increase federal revenues. From 1954 to 1990, the federal government received more than $93 billion in lease sales and royalties. According to the U.S. General Accounting Office, oil and gas royalties account for approximately 40 percent, and 60 percent, respectively, of the total OCS revenues earned by the Federal government. In 1989, the Gulf region accounted for more than 90 percent of oil and gas royalties paid. The U.S. Department of the Interior's Minerals Management Service, the agency responsible for managing federal offshore oil and gas operations, produces more revenue for the federal government than any other agency except the Internal Revenue Service. Currently, only the Gulf of Mexico and the Pacific regions have producing offshore leases.
- OCS development will provide additional time for the implementation of new and alternative sources of energy. Although conservation of energy resources must be an integral part of national energy policy, the U.S. will continue to be dependent on oil for a long time to come. Although the use of alternate fuels is increasing, oil supplies 97 percent of the energy used in the transportation sector; this is not likely to change in the near future. It is estimated that at current consumption levels, alternate transportation fuels (e.g., ethanol, propane, electricity, and compressed natural gas) could operate our transportation system for less than four days. Additional research and development must be conducted to extend the use of alternate-fuel vehicles.
- OCS development will strengthen the national economy as jobs are created and spending is generated in the drilling and related services industries. Coastal state economies could also be expected to improve as employment opportunities expand in these areas.

At the very least, the Chamber supports a vigorous, environmentally responsible leasing program in all offshore areas, such as that proposed by the U.S. Department of the Interior in its recently released draft Five-Year Plan. These areas include the Mid- and South-Atlantic coast; the Eastern, Central, and Western Gulf of Mexico; the Pacific coastline from San Luis Obispo to Santa Barbara; and Alaska's Beaufort Sea, Chukchi Sea, Cook Inlet, Bering Sea, and Yukatat region. Furthermore, because it can take as long as 15 years to bring a new offshore field to full production, Congress should remove restrictions on developing existing leases. If the United States is to develop new oil and gas resources that will reduce its demand for imports and reduce the threat of oil spills, access to these federal lands must be provided.

OCS DEVELOPMENT IS ENVIRONMENTALLY RESPONSIBLE

The petroleum industry's record of more than 35 years provides overwhelming evidence that OCS operations can take place without harming the environment. Oil companies must obtain 17 major permits and comply with 90 sets of federal regulations to operate on the OCS. These operations must also be consistent with state coastal management programs.

Evidence also indicates that offshore activities have minimal impact on onshore air quality. For example, OCS operations in California's Santa Barbara Channel account for less than five percent of the onshore emissions inventory. Indeed, such emissions are regulated under the Clean Air Act.

CONCLUSION

Continued orderly oil and gas development, under responsible environmental safeguards, is vitally important to the nation's energy and economic well-being. Production of oil and gas from the OCS has the potential to make a substantial contribution to domestic energy supplies. Such affordable sources of energy would help keep down the price of virtually all U.S. goods and services, preventing this nation from losing further ground to its international competitors in the global marketplace.

Steps must be taken now to provide access to the OCS. A national policy, in which coastal states and communities affected by leasing are permitted to share in offshore oil revenues, will provide new incentives for the OCS program, and provide a portion of the nation's resources for the benefit of all.

STATE OF TEXAS
OFFICE OF THE GOVERNOR
AUSTIN, TEXAS 78711

ANN W. RICHARDS
GOVERNOR

April 12, 1991

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Senator Johnston:

The provisions contained in S. 341 relating to compensation to states for impacts resulting from the development of adjacent federal tracts seem to be entirely appropriate. As the Coastal Energy Impact Program clearly recognizes, offshore development almost always places a serious strain on the onshore infrastructure, causes burdens to be placed on the people who live in the adjacent onshore areas, and forces changes in communities which are not always ready or equipped to deal with those changes.

For these reasons, I believe your approach is sound in this particular area of the Act.

Sincerely,

Ann W. Richards

Ann W. Richards
Governor

AWR/ba

POST OFFICE BOX 12428 AUSTIN, TEXAS 78711 (512) 463-2000

STATE OF ALABAMA
GOVERNOR'S OFFICE
MONTGOMERY 36130

GUY HUNT
GOVERNOR

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1991 MAR 21 PM 3:09

March 18, 1991

The Honorable J. Bennett Johnston
Chairman, Committee on Energy
and Natural Resources
United States Senate
Washington, D.C. 20510-6150

Dear Senator Johnston:

Thank you for your letter of February 27, 1991, regarding certain provisions in S 341, the National Energy Security Act of 1991. We support those provisions contained in pages 88-93 of Section 8001 entitled "Coastal State Community Outer Continental Shelf Impact Assistance" of S. 341. These provisions pertain to impact assistance to coastal states and communities relating to oil and gas development and production on the Outer Continental Shelf) (OCS). It is our understanding that these provisions would provide revenues to the coastal states in addition to the revenues received by the states under other provisions of the law, including section 8(g) of the Outer Continental Shelf Lands Act, as amended. With regard to the sharing of royalty revenues resulting from oil and gas production from OCS tracts, we would recommend that distribution of those revenues derived from natural gas production be on an equitable basis with the revenues derived from oil production.

As you may be aware, Alabama is emerging as a significant oil and gas producing state. We anticipate being a major supplier of natural gas for the nation when the deep natural gas resources in offshore Alabama are at optimum production. We have consistently supported energy programs that expedite oil and gas exploration and production, while providing careful and due consideration of environmental concerns. The discovery of new oil and gas reserves and a continued focused inventory of our potential oil and gas resources, particularly those resources of the OCS areas, are vital to national energy security. We believe, however, that those coastal states and communities affected by OCS activities should receive a fair share of the financial benefits of such development and production.

OCS leasing, drilling, and production continues to be focused on the Central and Western Gulf of Mexico areas. The new Comprehensive OCS Natural Gas and Oil Resource Management Program for 1992-1997 proposes up to 23 sales. Ten of the sales, or 43 percent, are scheduled for the Central and Western Gulf of Mexico areas. With such an emphasis on the Gulf of Mexico, we maintain that the four coastal states, including Alabama, chiefly affected by OCS activities should have an opportunity to share in the financial benefits resulting from these activities. We believe S. 341 would provide Alabama with a fair share of the benefits resulting from OCS leasing activities.

We have recently learned that the majority of the natural gas produced from OCS tracts off our coast will be brought ashore by pipelines to cleansing and processing facilities in southern Mobile County. This plan of action is logical because the industry infrastructure necessary for such operations is in place in Mobile County. The infrastructure was established to process the natural gas produced from state coastal tracts. We support the centralization of these cleansing and processing facilities in southern Alabama but maintain that our affected coastal communities should have an opportunity to share in the financial benefits resulting from this OCS production. We believe S. 341 would provide Alabama communities with a fair share of the benefits resulting from OCS Production.

If you have any questions concerning oil and gas activities off Alabama's coast, please have your staff contact Ernest A. Mancini, Director of the Geological Survey of Alabama at (205) 349-2852.

Sincerely,

Guy Hunt

Guy Hunt
Governor

CC: Dr. Ernest A. Mancini

STATE OF CALIFORNIA

JAMES M. STROCK
Secretary for Environmental Protection
555 Capitol Mall, P.O. Box 2815
Sacramento, CA 95812
(916) 445-3846

PETE WILSON, *Governor*

March 22, 1991

1991 APR -1 AM 8:11

[illegible] D.C. 20510

The Honorable J. Bennett Johnston
Chairman
United States Senate Committee on
Energy and Natural Resources
Washington, DC 20510-6150

Dear Senator Johnston:

As his OCS Policy Coordinator, Governor Wilson has asked me to respond to your request for comments on the energy impact assistance provisions of S. 341, the "National Energy Security Act of 1991." The Governor has also asked me to express his appreciation for your solicitation of our views on this proposal, which could directly affect California and our coastal local governments.

As you know, the Secretary of the Interior has recently released his Draft Proposed Comprehensive OCS Natural Gas and Oil Resource Management Program, and is currently in the midst of the consultation process with the coastal governors pursuant to section 18 of the Outer Continental Shelf Lands Act, as amended. This Program includes a proposal for revenue sharing with coastal state and local governments, although the details have not yet been set. On behalf of Governor Wilson, I am currently conducting an extensive public participation process that will be used to prepare the Governor's comments to Secretary Lujan. This process includes public hearings, meetings with local governments and other interested parties, and detailed reviews by State and local agencies. One issue we have highlighted in this process is the broad question of revenue sharing as contemplated by Interior.

The results of this public participation process and the Governor's formal response to Interior unfortunately will not be available prior to March 22. Rather than pre-judging the public input on this issue, I would prefer to delay a detailed response to the proposed provisions of S. 341. Instead, I will be happy to provide you with copies of the Governor's comment package to Interior once it is available at the end of April. I will also be prepared at that time to provide a more thorough analysis of S. 341 as its provisions would affect California. In the meantime, however, I would also like to provide some general information for your consideration, as discussed below.

Currently, the only form of impact compensation received by the states from federal offshore energy activities derives from the provisions of section 8(g) of the Outer Continental Shelf Lands Act, as amended. Most of the other coastal states have statutory and/or constitutional restrictions on the use of these funds, and have generally allocated them according to the procedures set for energy revenues from state waters. Typically, these uses have been limited to general fund purposes and trust funds for education and natural resource conservation.

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California has established no such restrictions on our 8(g) funds, and has applied these monies to a variety of activities. These uses have included programs established to address directly impacts from offshore oil and gas activities in both federal and State waters. One program consists of a multi-element approach to addressing impacts on California's commercial fishing industry. The other provides grants from the 8(g) revenues to coastal counties and cities for a variety of planning and mitigation purposes related to offshore energy. This second program in particular was established as a permanent vehicle which could be used to allocate federal impact assistance funds to our coastal local governments, and is an existing means which could be used to implement section 4(b) of S. 341. We are currently completing an evaluation of both programs, and I will be happy to provide you with copies of the reports once they are available. The evaluation of the local government assistance program should be released publicly in May. The evaluation of the fisheries program should be ready by July.

There are several broad issues raised by the proposed provisions of S. 341. First, impact assistance would only be derived from "new" OCS revenues. California along with the Gulf Coast are the only two areas in the United States with existing offshore oil and gas development in federal waters. Offshore oil has existed in California in some form since 1898, and in federal waters since 1954. Our local governments adjacent to this existing development have long maintained that impact assistance should be provided to address both past and future impacts, similar to the long-standing revenue sharing provisions that have been in place for onshore federal oil development. S. 341 would limit the funds available to those areas of the country that have sustained impacts in the past.

Other local governments in California have also objected to similar proposals along this line, that would tie impact assistance to accepting expanded offshore development. They have argued that revenue sharing should not be used to try to overcome community objections to the risks posed by offshore development, and that instead, the federal OCS leasing program needs to become more responsive to protecting our coastal and ocean resources where the risks from development are clearly too high.

Again, we appreciate this opportunity to provide preliminary comments on S. 341. If you have any questions on this information, please feel free to contact me or have your staff contact my staff or Ben Haddad of the Governor's Washington Office. I also look forward to providing you with more detailed comments on the specifics of this proposal, following completion of our public participation process on Interior's draft leasing program.

Sincerely,

James M. Strock
Secretary

cc: Ben Haddad

OFFICIAL COMMITTEE FILE
PLEASE RETURN

STATE OF FLORIDA
Office of the Governor
THE CAPITOL
TALLAHASSEE, FLORIDA 32399-0001

WTON CHILES
GOVERNOR

March 21, 1991

GY AND NATURAL RESOU
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MAR 22 1991
WASHINGTON, D.C. 205

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
364 Dirksen Senate Office Building
Washington, D.C. 20510-6150

Dear Senator ~~Johnston~~ Bennett

Thank you for your February 27, 1991 letter requesting my views on the impact assistance provisions contained in S. 341, the "National Energy Security Act of 1991." These provisions concern providing funds to coastal states and communities which are impacted by Outer Continental Shelf (OCS) oil and gas development and production.

In regulations promulgated under the Coastal Zone Management Act's Coastal Energy Impact Program (CEIP), it is clearly recognized that States can reasonably expect to be exposed to significant environmental, economic or social consequences as a result of OCS activities. Because funds are no longer available through the CEIP program for states to cope with impacts from OCS oil and gas activities and they are still occurring, it is most appropriate for states to share in the revenues generated from these activities.

Use of the impact assistance funds should include state and local government participation in carrying out responsibilities under the OCS Lands Act. These responsibilities include participating in the administrative, policy, operational and managerial decisions relating to management of the oil and natural gas resources of the OCS.

Funds should also be used for other planning, construction and maintenance of public facilities and provision of public service for those areas of the state that are socially or economically impacted by OCS activities.

Although I support the concept of impact assistance to coastal states and communities, I plan to work with the Florida Congressional Delegation in deciding the most appropriate formula for determining funds available and the allocation of such funds.

I appreciate the opportunity to comment on the impact assistance provisions of the "National Energy Security Act of 1991." Since I have not had the opportunity to review the other provisions of your bill, my support of the concept of impact assistance should not be construed as support for other portions of the Act.

With kind regards, I am

Sincerely,

LAWTON CHILES

LC/ddt

cc: Florida Congressional Delegation

The Commonwealth of Massachusetts
Executive Office of Environmental Affairs
100 Cambridge Street, Boston, 02202

WILLIAM F. WELD
GOVERNOR
ARGEO PAUL CELLUCCI
LIEUTENANT GOVERNOR
SUSAN F. TIERNEY
SECRETARY

(617) 727-9800

1991 MAR 27 AM 6 38

March 22, 1991

SENATE COMMITTEE ON
ENERGY AND NATURAL RESOURCES
RECEIVED
APR 1 1991
WASHINGTON, D.C. 20510

The Honorable J. Bennett Johnston
Chairman
Senate Committee on Energy and
Natural Resources
364 Dirksen Senate Office Building
Washington, D.C. 20510-6160

Dear Chairman Johnston:

Governor Weld has asked me to respond to your request to express the views of the Commonwealth of Massachusetts on certain provisions of S. 341, the "National Energy Security Act of 1991." As I am sure you know, the Commonwealth of Massachusetts has a strong commitment to the proper management of coastal and ocean resources and I appreciate the opportunity to comment on this very important issue.

The Commonwealth supports the concept of Outer Continental Shelf (OCS) oil and gas revenue sharing provided it recognizes the involvement of all coastal states that have approved coastal programs pursuant to the federal Coastal Zone Management Act. The use of offshore non-renewable resources, as part of a federal development program, affect more states than just those adjacent to the activity. Coastal states that do not have active OCS oil and gas activities, like Massachusetts, remain involved with the OCS Leasing Program by reviewing and commenting on multi-year lease sale plans and thus still incur administrative costs. In addition, they are often affected by the transportation and handling of the resource once it has been extracted.

For the reasons outlined above, I urge the Committee to amend Section 4 of S. 341 so that all coastal states with approved coastal programs would be eligible under the proposed Coastal State and Community Outer Continental Shelf Impact Assistance Fund.

Sincerely,

Susan F. Tierney

Susan F. Tierney,
Secretary

100% RECYCLED PAPER

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STATE OF MISSISSIPPI
RAY MABUS
GOVERNOR

March 22, 1991

Honorable J. Bennett Johnston
Chairman, Committee on Energy
  and Natural Resources
Washington, D.C. 20510-6150

Dear Bennett:

I hope things are going well for you this session. I received your letter concerning the provisions of Senate Bill 341 and am glad to know you are looking after the interests of our states regarding revenues from offshore oil and gas production. I appreciate your letting me know about this bill and giving me a chance to comment.

Since the federal government ceased funding the original Coastal Energy Impact Program, the states have come up short in revenues from offshore oil and gas development and production. The State of Mississippi's position is that on-shore impacts should be considered, notwithstanding the court ruling which limited the federal coastal impact program. Therefore, I support your effort to address the need through direct production revenues rather than fund allocations, if those revenues are in addition to revenues provided under the provisions of the law, including section 8 (g) of the Outer Continental Shelf Lands Act, as amended.

I hope you are successful in getting this legislation passed and look forward to seeing you again before too long. Let me know if you need further comment on this issue or if I may be of assistance in any way.

Sincerely,

Ray Mabus

RAY MABUS
Governor

RM:AH:rc

POST OFFICE BOX 139, JACKSON, MISSISSIPPI 39205, 601-359-3100

E✓

1991 MAR 25 PM 2:31

STATE OF NORTH CAROLINA
OFFICE OF THE GOVERNOR
RALEIGH 27603-8001

JAMES G. MARTIN
GOVERNOR

March 12, 1991

The Honorable J. Bennett Johnston
Chairman
Senate Committee on Energy and Natural Resources
Washington, D.C. 20510-6150

Dear Senator Johnston:

This letter responds to your request of February 27 for North Carolina's views on certain provisions of S. 341. Those provisions pertain to OCS revenue sharing with affected coastal states.

I was pleased to see that your bill embodies a concept that this state has long supported. We believe that OCS revenue sharing is long overdue. After CEIP funds dried up, the states were without federal assistance to offset the often significant impacts that occur from adjacent OCS activities. As Interior's new proposed 5-year OCS leasing program so clearly states, "the benefits of production for the most part accrue to the Nation as a whole while the associated environmental costs are borne mostly by the coastal areas in proximity to production activity." I believe your bill has the potential to rectify this inequitable situation affecting coastal states.

The amount to be paid into the Fund should be no less than 37.5%, the amount specified in your bill. The formulae for sharing revenues with the coastal states seem fair. I am particularly pleased that your bill allows the revenues to be passed to the states, which decide how sharing at the local level will occur.

North Carolina's lateral seaward boundaries have been defined and fixed by law, so we are ready and anxious to move forward on this important piece of legislation. I appreciate the opportunity to review your bill, and I hope these comments will be useful to you.

Sincerely,

Jim Martin

James G. Martin

cc: Hon. Walter Jones

State of Louisiana
Department of Environmental Quality

BUDDY ROEMER
Governor

PAUL TEMPLET
Secretary

MAR 25 PM 12

March 18, 1991

ENERGY AND NATURAL RES
RECEIVED
MAR 20 1991
WASHINGTON, D.C. 20510

Honorable J. Bennett Johnston
Chairman
United States Senate
Committee on Energy and
Natural Resources
Washington, DC 20510-0150

Dear Senator Johnston:

This is in response to your request for comments regarding S. 341 the "National Energy Security Act of 1991". I recommend the following changes:

(~~strike through~~ means delete; **bold** means add)

"(b) COUNTY AND COMMUNITY IMPACT ASSISTANCE.—The revenues paid by the Secretary to a coastal State under subsection (a) shall be used by such State and its subdivisions, as the ~~legislature~~ **Governor** of the State may direct, giving priority to those subdivisions of the State socially, **environmentally** or economically impacted by development of minerals on the Outer Continental Shelf, for (i) planning, (ii) construction and maintenance of public facilities, **environmental remediation,** and (iii) provision of public services.

If I can be of any further assistance to you, please let me know.

Yours very truly,

Paul H. Templet

Paul H. Templet, Ph.D.
Secretary

PHT/JLL/uda
c: Dave Chambers
Office of the Governor

OFFICE OF THE SECRETARY P.O. BOX 44066 BATON ROUGE, LOUISIANA 70804
FAX (504) 342-3743 AN EQUAL OPPORTUNITY EMPLOYER (504) 342-9103

State of Louisiana
OFFICE OF THE GOVERNOR
Baton Rouge
70804-9004

BUDDY ROEMER
GOVERNOR

POST OFFICE BOX 94004
(504) 342-7015

1991 MAR 28 PM 10:55

1991
WASHINGTON, D.C. 20510

March 21, 1991

The Honorable J. Bennett Johnston
Chairman, Committee on Energy and
Natural Resources
Washington, D.C. 20510-6150

Dear Senator Johnston:

I am writing on behalf of Governor Roemer in response to your request for comments on the OCS impact assistance provisions of S. 341, the National Energy Security Act of 1991.

We strongly support the concept and rationale for OCS impact assistance and believe that the 37.5 percent of such revenues to be shared with the states under S. 341 is more equitable than the amount proposed by the Minerals Management Service. Further, we support your approach in that the percent to be shared does not decrease with distance from shore and that impact assistance monies include a share of all bonuses, rents and royalties associated with new OCS leasing. We also concur with your method for defining boundaries offshore from coastal states.

We suggest that Section 4(b) on page 92 be modified so that 50% of the impact assistance monies identified in subsection (a) are provided directly to the state and deposited into such dedicated fund as may be established by a state specifically to mitigate or offset impacts to its coastal environment, including wetlands, barrier islands, cheniers, estuaries or other important coastal features. In Louisiana, we will be proposing legislation during the upcoming session to establish such a fund. The draft bill (copy attached) is widely supported by coastal legislators and will be part of the Governor's legislative package.

The remaining 50% of the monies identified in subsection (a) should be disbursed directly to impacted communities and political subdivisions of each state as directed by the legislature of such state for the purposes identified in lines 23 and 24 (page 92) of your bill. In this way both environmental and socioeconomic impact assistance needs of the state of Louisiana and other coastal states will be most equitably addressed.

With kindest regards,

Sincerely,

David Chambers

David Chambers
Executive Assistant
for Coastal Activities

HLS 91-480

Regular Session, 1991

HOUSE BILL NO. DRAFT DRAFT DRAFT

BY REPRESENTATIVE ROACH AND SENATOR NUNEZ

ENVIRONMENT/QUALITY: Creates the Coastal Environment Protection Trust Fund

AN ACT

To enact Chapter V-A of Title 30 of the Louisiana Revised Statutes of 1950, to be comprised of R.S. 30:311 through 30:316, to create the Coastal Environment Protection Trust Fund; to provide for the purposes of the fund, definitions, investment of monies in the fund; to provide for the disbursement and administration of monies; to provide for the development of a coastal environment protection plan; and to provide for related matters.

Be it enacted by the Legislature of Louisiana:

Section 1. Chapter V-A of Title 30 of the Louisiana Revised Statutes of 1950, comprising R.S. 30:311 through 30:316 is hereby enacted to read as follows:

CHAPTER V-A. COASTAL ENVIRONMENT PROTECTION TRUST FUND

§311. Policy and purpose

It is the determination of the legislature that the erosion and deterioration of many of the state's important coastal features including barrier islands, cheniers, and other coastal habitats will, within the years to come, continue and that such loss and deterioration of these features and habitats will cause a decrease in the quality of life, in the renewable resources and revenues derived therefrom, and in the private and public trust benefits provided to this state and to the nation. While

CODING: Words in ~~struck through~~ type are deletions from existing law; words underlined are additions.

the Wetlands Conservation and Restoration Trust Fund established in R.S. 49:213.7 provides for a dedicated and recurring source of revenue for the development and implementation of a program to help conserve and restore Louisiana's coastal vegetated wetlands, no mechanism presently exists for the state to adequately address the loss of other important coastal features and habitats. In order to preserve the benefits from these lands for future generations, it is the purpose of this Chapter to establish a special fund in the state treasury into which certain revenues shall be deposited and out of which they should be expended, as provided by law, to prevent, control, or offset such coastal erosion, subsidence, and habitat deterioration.

The legislature also intends, by establishing this special fund, to allow the state to be able to participate more fully and in a wider array of needed cost-shared projects under the provisions of Title III of P.L. 101-646, also known as the "Wetlands Planning, Protection, and Restoration Act" and under other federal programs with similar purposes, and to provide a means for the state to make a long-term commitment towards funding its share of existing and future costs for operation, maintenance, rehabilitation and monitoring of coastal restoration and protection projects, in accordance with applicable statutes, interagency or cooperative agreements, or project permits or plans.

It is the further intention of the legislature that this special fund serve as the repository for any new or additional revenues, exclusive of those to be distributed in accordance with the provisions of La. Const. Art. VII, §10.1, that are derived from the leasing, exploration, mining, or production of minerals from the federal outer continental shelf waters and lands offshore from the state of Louisiana and are designated by the United States Congress to be provided to the state, in the form of impact assistance, as block grants, or in any other manner.

§312. Definitions

The following terms shall have the meanings ascribed to them below:

(1) "Executive assistant" means the governor's executive assistant for coastal activities as established in R.S. 9:213.3(B), who in accordance with R.S. 49:213.5(C) serves as chairman of the Coastal Wetlands Conservation and Restoration Task Force.

(2) "Fund" means the Coastal Environment Protection Trust Fund.

(3) "Task force" means the Coastal Wetlands Conservation and Restoration Task Force as established in R.S. 49:213.5.

§313. Coastal Environment Protection Trust Fund; established

There is hereby established a fund in the state treasury to be known as the Coastal Environment Protection Trust Fund. The fund shall consist of such monies as may be appropriated to it by the legislature. In addition, the state treasurer shall deposit into the fund any new revenues, excluding those to be distributed in accordance with the provisions of La. Const. Art. VII, §10.1 that are derived from the leasing, exploration, mining or production of minerals from the federal outer continental shelf waters and lands offshore from the state of Louisiana and that are designated by the United States Congress to be provided to the state, in the form of impact assistance monies, as block grants, or in any other manner. Monies appropriated from the fund shall be expended only in accordance with R.S. 30:315 and 316.

§314. Investment of monies in fund

Monies in the fund shall be invested by the state treasurer in accordance with the law, and the investment earnings shall be credited to the fund. The treasurer shall advise the governor and the legislature of the status of the fund thirty days prior to each regular session of the legislature and at any other time upon their request.

§315 Disbursement; administration; coastal plan

A. The executive assistant shall initiate the process whereby monies appropriated from the fund shall be allocated for purposes and projects as provided in R.S. 30:316. He shall be assisted by the Task Force in the preparation of an annual coastal environment protection plan for expenditures from the fund and shall employ necessary staff to carry out the duties and functions required under R.S. 30:316. The development, preparation, public notice, and approval of the annual coastal environment protection plan shall be performed concurrently with and using the procedures specified in R.S. 49:213.6 for development of the annual coastal wetlands conservation and restoration plan, except that the coastal environment protection plan shall not be limited to projects or programs designed to conserve, manage, enhance, restore or protect vegetated wetlands. The coastal environment protection plan shall be submitted to the legislative committees on natural resources concurrently with the annual wetlands conservation and restoration plan provided for in R.S. 49:213.4.

B. The executive assistant may establish a panel of coastal experts from the state's universities and colleges, and such other experts as he may deem appropriate, to act as a clearinghouse for new coastal research ideas, to serve as a mechanism for building consensus regarding coastal study proposals most deserving of state or federal funding, to facilitate the transfer of scientific data among coastal researchers and administrators, and to provide advice as may be needed by the Task Force in regard to the following topics related to coastal land loss and habitat deterioration:

(1) New technology development and evaluation.

(2) Design of innovative monitoring and project evaluation programs to determine why successful coastal restoration and protection projects work and to help identify other coastal areas in the state where similar projects should also be effective.

(3) Determination of which critical physical and biological processes and parameters are most important in causing and offsetting coastal habitat deterioration.

(4) Complex and controversial legal and policy issues.

§316. Authorized purposes

A. Monies from the fund shall be used only for the following purposes related to coastal protection:

(1) Development and implementation of the annual coastal environment protection plan, including planning, design, construction, operation, maintenance, rehabilitation, and essential monitoring of coastal protection, restoration, or enhancement projects.

(2) Pilot projects for protection and restoration of coastal features or habitats and study and research into coastal problems, not to exceed five percent of the total appropriation each year for implementation of the coastal environment protection plan, subject to approval by the Task Force.

(5) Matching monies for federal, local or private funds for programs or projects consistent with R.S. 30:311-316 and approved by the Task Force.

B. The executive assistant may use monies appropriated from the fund for the administrative costs relative to the operation of the Task Force and the advisory panel of coastal experts as needed.

Section 2. This Act shall become effective upon signature by the governor or, if not signed by the governor, upon expiration of the time for bills to become law without signature by the governor, as provided in Article III, Section 18 of the Constitution of Louisiana.

GENERAL COUNSEL OF THE DEPARTMENT OF DEFENSE
WASHINGTON, D.C. 20301-1600

24 APR 1991

ERGY AND NATURAL RESOU
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APR 24 1991
WASHINGTON, D.C. 205

Honorable J. Bennett Johnston
Chairman, Senate Committee on
Energy and Natural Resources
Washington, DC 20510-6150

Dear Mr. Chairman:

This is in response to your request of March 26, 1991 for the views of the Secretary of Defense on Title VII, S. 341, 102nd Congress, a bill "To reduce the Nation's dependence on imported oil to provide for the energy security of the Nation and for other purposes."

We are pleased to provide the Department of Defense comments below on Title VII, and would like to take this opportunity to comment on Title III of the bill, as well. The National Defense Authorization Act for Fiscal Year 1991 established energy conservation guidelines for the Department of Defense. Title III, Subtitle B, of S. 341, applies similar provisions to all agencies. Our main concern with Subtitle B is the requirement to install not later than January 1, 2000, "...all energy conservation measures with payback periods of less than ten years...." We estimate that this goal could cost $2 billion, eight times the amount that is affordable through FY 1997. We prefer the approach in Executive Order 12759, Federal Energy Management," April 17, 1991, which is consistent with the Fiscal Year 1991 Defense Authorization Act and allows Agencies to set goals and prescribe the means to achieve them.

Title VII, S. 341, would require oil importers to provide at least 220,000 barrels per day of crude oil for the Strategic Petroleum Reserve and petroleum products to meet the Defense Department's demand (currently approximately 475,000 barrels per day). We understand the Committee's concern for energy security, but we are opposed to this proposal. The Defense provision appears impossible to implement without hurting the petroleum market and our source selection flexibility, and would raise the cost of oil and oil substitutes in the U.S. It would impose increased costs on a broad segment of the economy that relies heavily on petroleum products for transportation, heating and raw materials for petrochemicals and other products. This would increase costs to defense as well as have other adverse economic impacts nationally.

We urge the Committee to adopt the Administration's proposal, S. 570, Title III, Subtitle B, to lease the Naval Petroleum Reserve No. 1 and create a Defense Petroleum Inventory (DPI), which can be drawn down at rates and for periods of time requested by the Department. Leasing Elk Hills and using part of the proceeds to create a Defense-controlled DPI is a practical, sensible approach we strongly endorse.

The Office of Management and Budget advises that, from the standpoint of the Administration's program, there is no objection to submission of this report for the consideration of the Committee.

Sincerely,

Terrence O'Donnell

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[illegible]

United States Senate
COMMITTEE ON
ENERGY AND NATURAL RESOURCES
WASHINGTON, DC 20510-6150

March 25, 1991

The Secretary of Defense
Department of Defense
Washington, DC 20301-1155

Dear Mr. Secretary:

The Senate Committee on Energy and Natural Resources is herewith transmitting S. 341* for your study and report. Please send your report, along with 50 copies, to the Committee on Energy and Natural Resources, SD-364, Dirksen Senate Office Building, Washington, DC 20510, Attention: Mia' Miranda. Hand delivered copies should be taken to SD-317.

Submit your report within 30 days. If you cannot do so, let us know as soon as possible.

Sincerely,

J. Bennett Johnston
Chairman

Enclosure

Referred also to: DOE, DOI (Titles 8 and 9), Transportation (Title 11)
FERC (Title 10) and OMB

*DOD-Title 7

31078

Attachment #1

04/24/1991

COALITION TO OPPOSE ENERGY TAXES SUITE 1200, 1100 - 15th STREET, N.W., WASHINGTON, D.C. 20005
PHONE: (202) 452-1880

WRITTEN STATEMENT OF THE
COALITION TO OPPOSE ENERGY TAXES
BEFORE THE
SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES
ON TITLE VII OF S. 341, THE "NATIONAL ENERGY SECURITY ACT"
MARCH 11, 1991

COET is an ad hoc group of petrochemical companies that are not vertically integrated with major oil companies and are therefore "independent" petrochemical companies. We tender this written statement in order to assure the Committee that independent petrochemical companies respectfully oppose the provision in Title VII of S. 341 requiring importers of crude oil and petroleum products to provide a percentage of their imports to the U.S. in order to fill the Strategic Petroleum Reserve ("SPR"). This provision is the functional equivalent of an oil import charge or tax.

We certainly are not opposed to an enlarged SPR, and if the public interest requires additional means to increase storage of petroleum, we respectfully urge that the means not be an oil import tax in any form. We would commend for your consideration an alternate means to achieve that goal, one without the negative consequences of an oil import tax, and that is the "leasing" of petroleum for storage purposes, an option well known to the Committee. Since the SPR is for national security purposes, benefitting all in this nation, its costs should be borne by the Government on a least cost basis, as "leasing" does.

Petrochemical companies are dependent on natural gas, natural gas liquids, and certain refined petroleum products as the "raw materials", or feedstocks, from which basic building blocks are created for the manufacturing and consumer markets in the United States and abroad, in competition with foreign-sourced petrochemicals. Therefore, any tax on imported oil, refined petroleum products, or petrochemicals is of great concern. Title VII of S. 341 contains a form of tax on imports.

While some might think that a tax that operates as a tariff barrier would appeal to independent petrochemical companies, we wish to assure the Committee that precisely the opposite is the case. Any form of tax carries with it the effect of raising the price of feedstocks and fuels for U.S. petrochemical production above that of their foreign competitors, impairing the ability to compete in both domestic and foreign markets.

An oil import tax will impact in three distinct ways:

o in States where petrochemical plants are located, such as in Texas and Louisiana, petrochemical production will be displaced by foreign imports, carrying with it the loss of jobs.

o in States where there are manufacturing plants dependent upon petrochemicals--such as plastics, man-made fibers and textiles, medicines, paints, coatings, tires, parts for vehicles of all descriptions, fertilizers, and a host of consumer products and chemicals--such plants will likely face both higher costs for their raw materials as well as the prospect of increasing imports of raw materials in hopes of mitigating the artificial cost of domestic sources.

o in addition, in those States where there are manufacturing plants dependent upon petrochemicals, production and jobs are threatened as foreign sources simply bypass the U.S. manufacturing base and supply finished products to the United States. For example, a petrochemical plant will produce the raw material for making tires and send this product to an American plant to be made into tires. With an oil import tax raising the cost of materials for the domestic producer of petrochemicals and the tire manufacturer, a importer can simply buy foreign manufactured tires.

Not only is the loss of domestic markets a serious prospect, but there is even less hope for competitiveness in world markets. The chemical industry, of which the petrochemical sector is a significant part, provided a positive trade surplus to the U.S. of $16.5 billion in 1990.

If domestic manufacturing industry loses market share as a result of an oil import tax, which has the effect of providing a tariff wall to facilitate the raising of prices for domestic production of oil, then this loss of markets in manufacturing will be felt in falling demand for the oil industry as well.

Leasing avoids the negative effects of an oil import tax and should satisfy concerns about national security without being a direct affront to those countries who stood shoulder-to-shoulder with America in Desert Shield and Desert Storm and whose cooperation is necessary in order to seek the goal of a New World Order.

Leasing might well have the effect of providing an alternate, and deferred, market for foreign producing countries that could mitigate the concerns expressed about over-production.

We appreciate your consideration of this statement.

Respectfully submitted,

F. Joseph Graham

F. Joseph Graham, Chairman

CENEX [illegible]

Box 64089, St. Paul, MN 55164-0089
Telephone (612) 451-5151

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March 14, 1991

Honorable J. Bennett Johnston
U.S. Senate
Washington, D.C. 20510-1802

Dear Senator Johnston

We extend our congratulations to you and Senator Wallop for introducing S.341, "The National Energy Security Act of 1991, to reduce the Nation's dependence on imported oil, to provide for the energy security of the Nation and for other purposes." The Bill is a comprehensive approach to a most difficult national challenge, and you are to be commended. We are particularly supportive of the provisions to open ANWR and the coastal areas for exploration and production.

However, Cenex is quite concerned by the far-reaching ramifications of Title VII, which would require, inter alia, that **oil importers donate to the U.S. "at no cost" those volumes of oil needed to meet the product needs of the Department of Defense and to fill the Strategic Petroleum Reserve at the rate of 220,000 barrels per day.**

The Strategic Petroleum Reserve and the Department of Defense were created to protect all Americans, and all Americans should share the costs. But, Title VII places the burden of paying for these vital national security organizations on oil importers and their customers.

As a regional agricultural cooperative serving some 1,925 local cooperatives in 14 northwestern States, Cenex is obligated to import significant volumes of Canadian crude oil and propane in order to meet the fuel needs of its farm and ranch customers. That import obligation should not carry with it an obligation for Cenex and its agricultural customers to shoulder a significantly greater share of the costs of our vital national security institutions.

A detailed statement of our position is enclosed. We respectfully request that the enclosed position paper be incorporated in the official record of the March 11 hearing on Title VII.

Cenex urges that the oil import premium program in Title VII be eliminated from S.341.

Sincerely,

Robert C. Oebser

Robert C. Oebser
Vice President
Petroleum Exploration, Production and Refining

Enclosure: Cenex Position Paper Re: Title VII, S.341

FARMERS UNION CENTRAL EXCHANGE, INCORPORATED • 5500 CENEX Drive, Inver Grove Heights, MN 55075

CENEX

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MARCH 14, 1991

SERIOUS PROBLEMS ASSOCIATED WITH TITLE VII - STRATEGIC PETROLEUM RESERVE

S.341 - THE NATIONAL ENERGY SECURITY ACT OF 1991

A. GENERAL PROVISIONS OF TITLE VII

Title VII, S.341 provides for the following:

- 1. Effective with fiscal year 1992, DOE shall implement a program to require that petroleum importers donate to the United States "at no cost" the volumes of crude oil and petroleum products needed to:
    - (a) Meet DOD's petroleum product needs; and
    - (b) Fill the Strategic Petroleum Reserve at the rate of 220,000 barrels per day.
- 2. The Secretary of Energy shall estimate, for each fiscal year, the donation rate (percentage) on petroleum importers by application of the following formula:

$$\text{Rate} = \frac{\text{220,000 b/d + Average DOD consumption in b/d}}{\text{Average imports, crude oil \& petroleum products in b/d}}$$

- 3. The Secretary shall also require that the petroleum in question be delivered to designated locations at designated times. [This implies that all transportation costs and intermediate storage costs are also to be borne by the importer].
- 4. The rates would probably vary from 8% to 10% of imports, depending on the estimates of DOD requirements and total U.S. imports as well as on the question whether Canadian imports would be exempted. The following sample calculation is taken from DOE data for the year 1989 [see enclosure 1].

$$\text{Rate} = \frac{\text{220,000 b/d + 483,000 b/d}}{\text{7,979,000 b/d}} = 8.81\%$$

MAIN OFFICES: FARMERS UNION CENTRAL EXCHANGE, INCORPORATED • 5500 CENEX Drive, Inver Grove Heights, MN 55077

- 5. If, in accordance with the provisions of the U.S./Canada Trade Agreement, Canada were to be exempted from the provisions of Title VII, the burden on those who import from countries other than Canada would be increased. In 1989, total imports of crude oil and products from Canada were 839,000 barrels per day. We calculate a new rate below, excluding Canadian imports in the denominator:

$$\boxed{\text{Rate} = \frac{220{,}000\ \text{b/d} + 483{,}000\ \text{b/d}}{7{,}140{,}000\ \text{b/d}} = 9.85\%}$$

B. THE PROBLEMS

Cenex opposes Title VII for the following three general reasons:

1. **It is inequitable and would create serious market distortions, particularly for the agricultural community in border and coastal states;**
2. **The proposed SPR/DOD program is administratively impracticable; and**
3. **It is not in the national interest.**

1. Inequitable

- a. The requirement is highly discriminatory in that it creates, at least initially, financial burdens only for those importers and regions dependent on imported petroleum product.
- b. The importer donation would grant a significant competitive advantage to those petroleum refiners and marketers who are not dependent on imports.
- c. Import-dependent refiners and marketers such as Cenex would find it difficult, if not impossible, to pass through all of the added tax, storage and transportation costs and would suffer significant competitive disadvantages relative to other non-importing refiners and marketers. The ultimate losers would be our farmer and rancher owners, who would not only pay higher prices but also suffer a loss in patronage refunds from their regional cooperative.

- d. The Department of Energy will be hard pressed to make timely decisions as to where to ship the product in question. Cenex could not possibly store, even for a short period of time, the ever-increasing volumes of crude oil and petroleum products purchased for donation, storage and delivery to the U.S. government. Construction of additional storage facilities would involve major capital expenditures and, possibly, significant environmental delays.

- e. The Northern Tier States are heavily dependent upon Canada for imports of crude oil and propane, and, to a lesser extent, for other petroleum products. Other agricultural States along the coastal plains are similarly dependent upon petroleum from foreign sources. These regions would bear a disproportionate share of the program's cost.

- f. Although importers would be filling the SPR, they would have no preferential position when SPR sales are conducted. Under the current wide-open universe, any financially responsible purchaser--including foreign countries--can bid for SPR oil. There is no equity here.

- g. The cost to Cenex in FY 92 would be on the order of $18 million, excluding transportation and storage costs and based upon recent Cenex import levels of crude oil and propane. This is a terrible burden for a company the size of Cenex, particularly in view of the major expenditures that must be made to conform to the requirements of the Clean Air Act Amendments of 1990. The likelihood is small that we would be able to recover the full costs of donated petroleum, transportation and storage.

2. Administratively Impracticable

The proposed SPR/DOD donor program is administratively impracticable in that, without significant augmentation, the DOE would find it most difficult to track all imports, relate them to DOD and SPR requirements, and issue timely instructions as to volumes, fair market values and destinations for selected crude oil and products.

- a. There is a gross mismatch between DOD product requirements and imported products, in terms of volume and location. For example, in 1989, the U.S. imported only 3,000 barrels per day of naphtha jet fuel--a volume far short of DOD consumption of 121,000 barrels per day of jet fuel, mostly of the naphtha variety.

For the DOD to get its supplies, there would necessarily be an extensive and burdensome exchange program involving "free" products for market value products of dissimilar types.

- b. Importers themselves would face great difficulties. For example, how would Cenex deliver sweet crude oil to the Gulf Coast SPR storage areas when the great preponderance of its crude oil is not sweet? How would Kelly Air Force Base in Texas assure timely delivery of jet fuel requirements in such a confusing arrangement? As indicated above, importers not having the required fuel on hand would have to enter into exchange arrangements to get the needed products to the DOD--exchange arrangements complicated by dealing with the government and exchanging free products for market value products.

- c. Insofar as the DOD is concerned, a production and delivery infrastructure established over many years would suddenly disappear in favor of DOE-ordered product deliveries. The Defense Fuel Supply Center is eminently qualified to insure delivery of needed products at the right time and place; they would be replaced apparently by untrained DOE experts.

3. Not in the National Interest

- a. The proposed donation program also has all of the disadvantages of an oil import fee. For example, other oil intensive industries such as the petrochemical industry would face serious disadvantages in the world market as a result of the higher prices and uncertainties mandated by Title VII.

- b. The proposed donation program might well be in violation of the U.S./Canada Free Trade Agreement in that it essentially establishes a unilateral oil import fee. Even if Cenex were thus exempted from the subject import fee, Cenex would still oppose the program for the reasons stated herein. Most importantly, the National Defense and the Strategic Petroleum Reserve have been created to benefit all Americans; all Americans should contribute to the maintenance of these vital national security institutions.

- c. There may be some significant political damage in letting it be known that the United States Department of Defense will become solely dependent on foreign sources for all of its fuel needs.

- d. The existing petroleum infrastructure in support of the Department of Defense will be seriously disrupted. A number of small refineries located near and primarily dedicated to supplying the fuel needs of military bases will be forced out of business.

C. CONCLUSION

Title VII, S.341 must be amended to eliminate the oil import premium program described in Section A. above.

Enclosure 1

Department of Defense

Petroleum Product Usage, FY 89

(1) Product	(2) Trillion Btu Per Year[1]	(3) Million Btu Per Barrel[2]	(4) Thousand Barrels Per Year	(5) Thousand Barrels Per Day
Motor Gasoline	18.6	5.253	3,541[3]	9.701[4]
Distillate & Residual Oil	272.0	6.056	44,914	123.052
Jet Fuel & Aviation Gas	684.5	5.355	127,824	350.204
Other	0.7	5.796	121	0.331
Total	975.8		176,400	483.288

Department of Defense

Petroleum Product Usage, FY 79

(1) Product	(2) Trillion Btu Per Year[1]	(3) Million Btu Per Barrel[2]	(4) Thousand Barrels Per Year	(5) Thousand Barrels Per Day
Motor Gasoline	29.1	5.253	5,540[3]	15.177[4]
Distillate & Residual Oil	291.4	6.056	48,118	131.829
Jet Fuel & Aviation Gas	615.2	5.355	114,883	314.749
Other	2.5	5.796	431	1.182
Total	938.2		168,972	462.937

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[1] Source: Table 10, Annual Energy Review, 1989, Department of Energy.

[2] Source: Table A1, Annual Energy Review, 1989, Department of Energy. The value for distillates and residual fuel oils is the average of the distillate value (5.825) and the residual value (6.287). The value for jet fuel and aviation gasoline is the value given for naphtha jet fuel. The value for "Other" is the value given for miscellaneous.

[3] Column (2) divided by Column (3) times 1,000.

[4] Column (4) divided by 365.

STATE OF CALIFORNIA
PETE WILSON, *Governor*

STATE LANDS COMMISSION

LEO T. McCARTHY, *Lieutenant Governor*
GRAY DAVIS, *Controller*
THOMAS W. HAYES, *Director of Finance*

EXECUTIVE OFFICE
1807 - 13th Street
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CHARLES WARREN
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April 12, 1991

The Honorable J. Bennett Johnston,
Chairman, Senate Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Senator Johnston:

We are submitting a statement in support of the Administration's proposal to lease the Elk Hills Naval Petroleum Reserve as forwarded to you by Robert E. Grady on April 10, 1991. This proposal merits your serious consideration, not only for the reasons set forth by Mr. Grady in his letter, but also because it would resolve a long-standing federal obligation by removing a cloud over the federal title to several sections of school lands within the Reserve.

We ask that this statement be incorporated in the record of the Committee's deliberations, and hope that the Committee will give this proposal favorable consideration.

Yours truly,

James Trout

James Trout
Assistant Executive Officer
California State Lands Commission

cc w/enc: Senator John Seymour
Senator Alan Cranston
Robert E. Grady

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

APR 10 1991

Honorable J. Bennett Johnston
Chairman, Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Senator Johnston:

I am writing to ask you and your colleagues to support the Administration's proposal to lease Elk Hills Naval petroleum reserve and to include it the legislative package of energy proposals you are working to produce.

The leasing proposal is consistent with the balanced package you are working on. In my view it makes good sense.

o It is fiscally responsible. It will reduce the budget deficit in each of the next five fiscal years. It is designed to maximize production at Elk Hills. It will produce a one billion dollar lease bonus payment in FY 1992 alone.

o It increases energy security. Elk Hills was set up to provide for Defense emergency petroleum requirements but under current arrangements Defense would have trouble getting any Elk Hills oil in an emergency. Our proposal corrects this situation. It creates a ten million barrel Defense petroleum inventory the Secretary of Defense could access at his discretion in an emergency.

o It encourages cost-effective domestic energy production in a manner that is fair to the people of the State of California and the taxpayers of the United States. It is designed to produce a "win-win" situation wherein both the Federal Treasury and the State of California can benefit from aggressive, businesslike management of Elk Hills.

Enclosed is draft Elk Hills leasing legislation the Administration supports in a form that can readily fit in the bill you are sponsoring. My staff and I are available to answer any questions you may have about this proposal. Thank you for your attention on this important matter.

Sincerely,

Bob Grady

Robert E. Grady
Associate Director for Natural Resources,
Energy and Science

AN IDENTICAL LETTER HAS BEEN SENT TO SENATOR MALCOLM WALLOP

STATEMENT ON S. 341 and S.570

BEFORE COMMITTEE ON ENERGY AND NATURAL RESOURCES

April 13, 1991

California State Lands Commission
Charles Warren
Executive Officer

SYNOPSIS OF TESTIMONY

In 1853, Congress entered into what courts have called a "solemn compact" with California. In it, it granted the State section 16 and 36 in every township in exchange for California's promise to dedicate those lands to its educational system, and to refrain from attempting to tax the extensive public lands retained by the federal government.

After 137 years, California's school land grant remains unfulfilled. Completion of the school grant has been stymied because the two most valuable school land sections in the State lie within Naval Petroleum Reserve No. 1 (Elk Hills).

Although the responsible federal agencies have repeatedly stated that Elk Hills no longer has any valid federal purpose, and it constitutes a reserve in name only, they claim to be powerless either to recognize California's title interest or provide as indemnity lands of comparable value.

Congress must take action to break this impasse. The Administration's proposal to lease Elk Hills, allocating a portion of the revenues to the State's school trust program, represents a fair and workable solution to this long-standing controversy. It has the following merits:

o It would compensate the State equitably for its long-withheld interest in the reserve;

o It would permit enhanced production through more long-range planning and greater capital improvements by the lessee;

o It would retain existing requirements for sales to small refiners; and

o It would remove a long-standing cloud on the reserve's title.

A copy of that proposed amendment is attached. It deserves the Committee's serious attention.

STATEMENT ON S. 341 and S. 570

Charles Warren, Executive Officer
California State Lands Commission

BEFORE COMMITTEE ON ENERGY AND NATURAL RESOURCES
ON BEHALF OF CALIFORNIA STATE LANDS COMMISSION

April 13, 1991

BACKGROUND

The administration has submitted proposed amendments to the national energy legislation before this Committee which provide an opportunity to solve one of the most pressing public land issues facing Congress today: satisfaction of the long-standing school land grant to California.

Within Naval Petroleum Reserve No. 1 at Elk Hills are two sections of school lands, part of the 1853 grant to California for the support of the public schools. (Act of March 3, 1853, 10 Stat. 244). These lands comprise about 1300 acres of the 47,985 encompassed by Elk Hills. They represent about 7.13 per cent of its total production of oil. Although they comprise a relatively small part of Elk Hills, they are easily the most valuable sections of school land in the State.

The school lands grant

The school grant, made to virtually every public land state since 1802, has been described as a "solemn agreement" that may be analogize to a contract between private parties," Andrus v. Utah, 446 U.S. at 507. Its specific purpose is to create "a binding permanent trust which would generate financial aid to support the public school systems of the 'public land' states." Utah v.

Kleppe, 586 F.2d 756 (10th Cir. 1976), rev'd on other grounds, Andrus v. Utah, 446 U.S. 500 (1980).

In the school grant, the United States agreed to make available random parcels of land (sections 16 and 36 in every township in California) in exchange for which the states waived their claims to possess or to tax the large portions of federal land withheld. It was intended to provide each state with "a proportionate part and fair cross section of all classes of land within its boundaries." Remarks of Senator Watkins, 104 Cong. Rec. 11919-11922 (1958).

Governmental land grants for school purposes date back to 1635, when the Massachusetts legislature made an island in Boston Harbor available to the town of Dorchester for its public schools. B. Hibbard, A History of Public Land Policies 306 (Macmillan 1924). The Land Ordinance of 1785 called for the reservation of section 16 of every township "for the maintenance of public schools..." P. Gates, History of Public Land Law Development 65 (1968).

School grants, being grants of specific sections, could not be finalized until the lands had been surveyed--which in many cases did not occur until well after statehood. Until the surveys were completed, legal title remained in the federal government. But nevertheless, there was a good faith obligation to fulfill the grant. As the Supreme Court stated in 1856, "[U]ntil the survey of the township and the designation of the specific section, the right of the States rests in compact--binding, it is true, the public faith, and dependent for execution upon the political authorities." Cooper v. Roberts, 59 U.S. (18 How.) 173, 179 (1856).

The federal government, as well as the states, benefitted from these school land compacts. First, as a condition of receiving the lands, states were required to use them to support public schools. Second, the United States received a disclaimer of any interest in the title to the lands retained by the federal government. And the federal government demanded that the states disclaim any taxing authority over federal lands. See *Andrus* v. *Utah*, 446 U.S. at 522-23. (For California's disclaimer, see 9 Stat. 452, § 3 (1850)).

The importance of the school grant cannot be overemphasized. President Teddy Roosevelt described it in the "Winning of the West" as the basis for the public school system.

Federal-state efforts to complete the grant in California fail

Originally, mineral lands did not pass under the school grant. In 1927, however, Congress provided that the states should receive title to mineral as well as other school sections. California would have received the Elk Hills sections at that time but for the fact that they had been included within the naval petroleum reserves--established to safeguard supplies for the oil-burning Navy in 1912.

The State made no objection to retention of the sections within Elk Hills so long as the naval petroleum reserve was in fact used as a reserve for the national defense. In 1976, however, Congress, reacting to the OPEC oil crisis, authorized production at the maximum efficient rate. In 1979, the revenues from Elk Hills were directed to the Treasury as miscellaneous receipts. Since then, with the exception of a short-term trial run through pipeline to the Strategic Petroleum Reserve and some minor sales to the Defense Department, Elk Hills has been operated as what the Energy Secretary Herrington described as a "cash cow"[1] for the federal Treasury, with no valid defense purpose.

Since 1976, when Elk Hills was put into full production, the federal government has received over $12.1 billion. California has received no part of these proceeds. None of those receipts were distributed under the Mineral Leasing Act formula (as they would have been had Elk Hills been treated like other public lands), and no monies attributable to the school lands were distributed to the State. Because these producing lands retained the label "Naval Petroleum Reserve," California's schools and teachers contributed nearly $7 billion to the federal treasury.

Elk Hills production peaked in 1981, when net revenues reached some $1.6 billion. Since then, production has been declining at about 13 per cent a year.

Since the early nineteen eighties, representatives of the State Lands Commission have been discussing the Elk Hills school lands with the Bureau of Land Management as part of the overall program to complete the school land grant. California's efforts to complete the school grant intensified with two occurrences:

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[1] Statement of Energy Secretary Herrington, Hearings of Energy and Water Development Appropriations for 1989: Hearings before the Subcomm. on Energy and Water Development of the House Comm. on Appropriations, 100th Cong., 2d Sess., Part 5 at 23 (March 10, 1988).

1) The Interior Department announced in 1980 that one of its principal objectives was completion of the long-delayed school grants throughout the West. As part of this program, it entered into an MOU with California declaring the school grant to be in the national interest under the Federal Land Policy and Management Act, that the State's outstanding entitlement rights "are to be considered as an obligation and debt due to the States by the Federal Government," and that "In the application of laws, regulations and policies on indemnity selections...the equities of the State [should be considered] to the greatest extent possible within the constraints of applicable law."

2) The Energy Department, acting as point agency for the federal administration, announced its intention to seek authority to sell Elk Hills and Teapot Dome, since the naval petroleum reserves no longer had any valid federal purpose. When the federal divestiture proposal was unveiled, no provision had been made for compensation of the State for its school lands.

Proposals for solution meet dead ends

As discussions with Interior proceeded, the State and the federal officials explored two possibilities for fulfilling the grant:

1. The provision of lands of equal value in place of the

two Elk Hills sections. This proposal involves the statutory requirement that "indemnity" lands be provided to replace school sections unavailable to the states because of their inclusion within reservations of various kinds. In Andrus v. Utah, 446 U.S. 500 (1980), the Supreme Court upheld the Secretary's imposition of an equal value standard for such indemnity selections to defeat Utah's claim to oil shale lands worth much more than certain school lands within national parks and monuments. The basis for that decision was that the school grant was intended to provide states with a "rough cross-section" of the public lands, with representative values.

Correspondingly, the provision for indemnity selections was designed to provide the states with substitutes of "roughly equal value" to the school sections withheld. Andrus v. Utah, 446 U.S. at 510.

Thus, California reasoned, if the State was properly denied a windfall in its selection, so should the federal government should be as well. Equitable solution to the school grant requires that if lands are selected to replace unavailable school sections, they should be roughly proportionate in value to those lost.

This effort led to a dead end for two reasons: the Interior Department contended that the statutory provision for indemnity selections was limited to lands of equal acreage (42

U.S.C. § 852) and there were no unappropriated public lands in California remotely comparable in value to the two Elk Hills sections.

2. Modification of the reserve to recognize the State's interest. Department of Interior officials suggested it might be possible to modify the reserve so as to recognize California's school land interest by permitting the State to receive title to the sections in place. In effect, this would permit the reserve to be continued subject to all federal standards and reserve requirements, but allow the revenue from those two sections to be diverted to California's school system.

This arrangement is supported by precedent. Presently more than one-fifth of Elk Hills is owned by Chevron and operated under unit agreement. The Department's Solicitor, however, has concluded that Congressional authority is necessary to implement this solution.

THE DECISION TO LITIGATE

In 1986, negotiations reached an impasse. The State BLM Director wrote to the Lands Commission stating he had been unable to interest the Department in taking any action to satisfy California's school land grant. The Energy Secretary wrote to the Governor and the Lands Commission chairman stating that in his view the state had no rights in the sections involved.

California then filed suit in the federal district court in

Fresno seeking recognition of the State's school land claims. The State made three arguments:

1. The reserve had been de facto revoked by the acts placing it in full production and channelling its revenues into the federal treasury. Representatives of the federal administration (notably the Energy Department) had stated numerous times that the reserve no longer filled any useful purpose and was one in name only[2]. This being the case, under the Jones Act title to the school sections automatically reverted to California.[3] The remainder of the reserve then constituted public lands, subject to leasing under the Mineral Leasing Act of 1920. Under that Act, 50 per cent of the

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[2] Indeed, as early as 1959, President Eisenhower said: "The continued and rapid growth in the use of petroleum products has made questionable the need for maintenance of the relatively small naval petroleum reserves as a significant defense measure, since it would appear that the nationwide, even world-wide, petroleum industry must be relied upon to provide efficiently for our petroleum requirements in both peace and war. Accordingly, the administration will study--and I would hope the Congress would do likewise--the advisability of disposing of the anachronistic naval petroleum reserves, thereby relieving the Department of the Navy of an inappropriate responsibility and also providing additional revenue to the Federal Government." - President's Budget Message-1959.

[3] 43 U.S.C. § 870(c) provides that school land grants of lands within the limit of existing reservations cannot be realized until such reservation is "extinguished, relinquished, or canceled." See, also, 43 U.S.C. § 851: "[A]ny State [may] await... the extinguishment of any such military...reservation and .. then tak[e]...the [school] sections...in place." These sections reflect previous holdings that the repeal of an act that had prevented "execution of the compact" operated at that date to "disencumber [the granted land], and subject [it] to the operation of the compact." Cooper v. Roberts, 59 U.S. (18 How.) 173, 181 (1856).

revenues from public land leases are shared with the states.

2. Alternatively, the State should be entitled to select federal lands of comparable value outside the reserve. To satisfy this requirement, the State must be empowered to select lands that were producing or producible, and lands greater in acreage than the two sections

3. The State contended that the Energy and Interior secretaries did in fact have authority to modify the reserve so as to pass title to California under the Federal Land Policy Management Act, and their failure to consider such actions constituted an abuse of discretion.

Amicus briefs in support of California were filed by the California Teachers Association and the states of Arizona, Idaho, South Dakota, Wyoming and Nebraska.

After extended consideration, the trial court granted in part a summary judgment motion filed by the federal government. It concluded "reluctantly" that the statute of limitations precludes California's claims to the sections within Elk Hills. However, it left open the State's claim to indemnity lands of comparable value. Still undecided are two remaining motions: the State's motion for a declaration of its right to select producing lands to replace the sections in the reserve, and a federal motion for reconsideration or clarification of that same point in favor of the defendant federal departments.

CONGRESSIONAL SOLUTION IS NEEDED

There is little doubt but that Congress must cut this Gordian knot in which the State and the federal agencies are bound. The Energy and Interior departments have declared themselves powerless to satisfy the obligations imposed upon them by Congress under the historic school lands grant.

The solution offered in the administration proposal has ample precedent in the acts of Congress taken over generations of negotiations over the nation's emerging public land policies:

1. Importance of the school land compact in American history. The school grant had its origins in the Massachusetts Bay Colony and the Ordinance of 1785. The policy of providing lands for schools goes back to the origins of the Republic.

2. The Mineral Leasing Act of 1920 guarantees states a share in public land revenues. The school land compact was only the first of several bargains made between Congress and the states over the public lands. The Mineral Leasing Act constitutes a compromise in which the public land states gave up their opposition to a federal policy of retention of the public lands in exchange for a major share of their revenue. The decision to lease the public mineral lands was a major break with tradition, and was recognized as such. As Congressman Taylor of Colorado stated: "The bill...changes the whole principle of the public land laws...by refusing

hereafter to allow the title to lands to go into private ownership and adopts for the future a Government leasing policy... While most of the people of the West believe it would be better if this land went into private ownership...and went onto the tax roll and became subject to taxation for local development and the support of any states and counties and schools and roads, that has all gone by and it is not before us at this time, and it is now agreed upon that we will adopt and try out this leasing policy." 59 Cong. Rec. 2711 (1920). But in making this decision, Congress decreed that the states would be compensated by 50 per cent of revenues from such leases.

3. Alaska entitled to 90 percent of NPR 4. In 1980, Congress terminated Naval Petroleum Reserve No. 4 to permit 90% of the revenues from its lands to go to the State of Alaska. P.L. 96-153 (Dec. 12, 1980), 94 Stat. 2835.

4. Military reservations on acquired lands subject to mineral revenue sharing. In 1981, Congress amended the Mineral Leasing Act for Acquired Lands to allow states to receive 50 per cent of the revenues from mineral leases on lands acquired for military purposes, except for the naval petroleum reserves and national oil shale reserves. The Department of the Interior supported that legislation, notwithstanding estimates of the first-year cost of $27.75 to $23.2 million.

5. The House Budget and Appropriations Committees support resolution of the State's claim. Since 1987, the Budget and Appropriations committees of the House have been stating their concerns over the federal government's failure to resolve California's claims. In the FY 1991 Conference Report, the House Budget Committee urged the Secretaries of Energy and Interior to "recognize and provide appropriate compensation for these state claims as soon as possible.'

6. The House Interior and Insular Affairs Committee has approved an equitable solution. In July, 1990, the House Committee on Interior and Insular affairs passed H.R. 5187 (H. Rept. 101-670). This bill, which was cosponsored by 44 members, would have required that oiland gas revenues from the two school sections be paid to the State.

The failure to carry out the historic school land bargain with California would constitute a break with precedent and established congressional policy.

CONCLUSION

The administration amendment provides a clear-cut and simple solution to the problem. It provides for the payment to California of seven per cent of any lease bonus payments and one-half the anticipated 12 1/2 percent royalties (an amount roughly proportional to the State's 7 1/2 per cent school land share of the revenue). By accepting these revenues, the State would waive any claims to the lands in place, to back payments and to indemnity lands. This proposal represents an equitable and appropriate resolution of the school lands problem.

We concur in the admissions of the Energy Department that Elk Hills no longer has any valid federal purpose. The Department has baldly stated that the role of the national petroleum reserves "has evolved over time from an emergency source of oil to an income-generating Federal business asset," and that "Federal ownership and operation of the NPR's is not essential to the National Energy Policy Plan (NEPP) goals and objectives." The only reason the school sections at issue here are being withheld from the State is to ensure the diversion of revenues from the State Teachers Retirement System to the federal treasury. We do not believe that Congress intended to breach its solemn agreement with the state and frustrate a school land grant solely for that purpose.

As the Supreme Court said long ago: "It is, of course, presumed that Congress will act in good faith; that it will not impair the scope of the school grant; that it intends that the state shall receive the particular sections or their equivalent in aid of its public school system." Minnesota v. Hitchcock, 185 U.S. 373, 393 (1902).

Proposed Amendment Authorizing the Leasing of Naval Petroleum Reserve Numbered 1

Amend S. 341 by inserting immediately after Title XV thereof the following new Title XVI:

"TITLE XVI - NAVAL PETROLEUM RESERVE NUMBERED 1 LEASING

"SECTION 16001. SHORT TITLE.

"This Act may be cited as the 'Naval Petroleum Reserve Leasing Act'.

"SEC. 16002. LEASING AUTHORIZATION.

"(a) Notwithstanding any other law, if the President finds that control and use of Naval Petroleum Reserve Numbered 1 by the United States is not necessary for national defense purposes or to assure its exploration, development, and operation, the Secretary of Energy (the "Secretary") may lease any or all of that reserve. As determined by the Secretary, portions of chapter 641 of title 10, United States Code, shall cease to apply with respect to the reserve from the effective date to be specified in a lease, and to the extent and under conditions that may be provided for elsewhere in this title.

"(b) The President shall submit a finding under this section to the Congress, together with a report on the basis for the finding, at least 60 days before the effective date of a lease of the reserve.

"(c)(1) The Secretary may use the United States' share of lease proceeds received in the 'Naval Petroleum Reserve Lease Proceeds Special Account' provided for in section 16006 of this title to satisfy contractual obligations directly related to the accomplishment of a lease and to pay any liabilities of the Department of Energy arising with respect to the interests leased at Naval Petroleum Reserve Numbered 1 and with respect to the settlement of issues under the Unit Plan Contract at Naval Petroleum Reserve Numbered 1, including any liabilities relating to payment of just compensation and under any Federal statute concerning the environment. The balance of funds received shall be utilized as provided in section 16006 of this title.

"(2) Before entering into a lease under this title, the Secretary shall determine that all compensation received under the lease represents fair market value.

"(d)(1) The Secretary shall notify the Attorney General of each proposed lease under this title. The notification shall contain information that the Attorney General may require in order to advise the Secretary as to whether the lease may substantially lessen competition. Within 30 days after the notification, the Attorney General shall advise the Secretary whether the lease may substantially lessen competition.

"(2) Nothing in this title confers on any person immunity from civil or criminal liability, or creates defenses to actions, under the antitrust laws.

"(3) As used in this section, the term 'antitrust laws' means--

"(A) the Sherman Act, as amended (15 U.S.C. 1 et seq.);

"(B) the Clayton Act, as amended (15 U.S.C. 12 et seq.);

"(C) the Federal Trade Commission Act, as amended (15 U.S.C. 41 et seq.);

"(D) sections 73 and 74 of the Wilson Tariff Act, as amended (15 U.S.C. 8 and 9); and

"(E) the Act of June 19, 1936, chapter 592 (commonly referred to as the 'Robinson-Patman Act'), as amended (15 U.S.C. 13, 13a, 13b, and 21a).

"(e) The Secretary shall conduct a leasing action under this title using competitive procedures and may reject any and all offers or bids for leases even if such offers or bids meet or exceed minimal acceptable levels.

"(f) Any leasing action or lease under this title shall require that a royalty payment equal to not less than 12.5 percent of the value, as determined by the Secretary, of the oil, natural gas, and other hydrocarbon resources of the production removed or sold from the lease be paid to the 'Naval Petroleum Reserve Lease Proceeds Special Account,' provided for in section 16006 of this title.

"(g) Any lease contract authorized under this title shall be so structured as to require parties leasing the reserve or any interest in the reserve to--

"(1) retain all records pertaining to the production, transportation and sale of production for a period of not less than 6 years, or such longer period as the Secretary by notice may require;

"(2) make all such records available to the Secretary for audit; and

"(3) provide that, in the event of late payment of royalties, partial payment of royalties, or failure to pay any royalties due, the Secretary shall require the payment of interest and penalties and may cancel the lease.

"(h) Any lease contract authorized under this title shall be so structured as to require parties leasing the reserve to set aside a portion of the crude oil produced to sell to small refiners for processing or use in such refineries, except that--

"(1) none of the production sold to small refiners may be resold in kind;

"(2) production must be sold at a cost of not less than the prevailing local market price of comparable petroleum; and

"(3) the set-aside portion shall not exceed 25 percent of the estimated annual production at the reserve.

"SEC. 16003. PROCEDURES TO ARRANGE AND CONDUCT A LEASING ACTION.

"(a) Before and after the President's finding under section 16002(a) of this title, the Secretary may take the steps the Secretary considers necessary to arrange the lease of Naval Petroleum Reserve Numbered 1.

"(b) In order to arrange and conduct a leasing action, the Secretary may--

"(1) create new corporations, partnerships, or other business entities, and transfer the United States' interest to the new entities;

"(2) enter into contracts with State or private entities, including contracts for technical, financial, auditing or other professional services; and

"(3) use funds appropriated to the Department of Energy under the Department of the Interior and Related Agencies Appropriation Acts, but not to exceed 5 percent from the Naval Petroleum Reserves Account.

Resources and expertise of other Federal agencies shall be used to lease the Reserve when doing so will reduce the cost to the Federal government of leasing.

"(c) Unless otherwise determined in accordance with section 16002(e), all lands to be leased shall be leased to the highest responsible qualified bidder or bidders by competitive bidding under general regulations issued by the Secretary. The Secretary may establish bidding and lease terms and conditions the Secretary considers necessary or appropriate, including, but not limited to, the establishment of the acreage and units of lands to be leased and the minimum rental or royalty rates.

"(d) A lessee of any of the United States' interest in Naval Petroleum Reserve Numbered 1 is not liable for any claim of liability arising exclusively from or during the ownership and operation of the interest by the United States. Such a claim may be asserted only against the United States to the extent and in the manner provided by law.

"SEC. 16004. PRIVATELY OWNED LANDS AND PHYSICAL IMPROVEMENTS.

"(a) Whenever the Secretary is otherwise unable to make arrangements the Secretary considers satisfactory for a lease of Naval Petroleum Reserve Numbered 1, the Secretary may acquire, by purchase, condemnation, or otherwise, privately owned lands or physical improvements within Naval Petroleum Reserve Numbered 1, as the Secretary considers necessary to facilitate the leasing action.

"(b) Before condemnation proceedings are instituted, an effort shall be made to acquire the property by negotiation, unless, in the judgment of the Secretary, the effort to acquire the property by negotiation would be futile or unduly time consuming, or otherwise not in the public interest.

"SEC. 16005. STRATEGIC PETROLEUM RESERVE TIE-IN; DEFENSE PETROLEUM INVENTORY.

"(a) In the event of a lease of any part of Naval Petroleum Reserve Numbered 1 under this title, sections 160(a), (b), and (d) of the Energy Policy and Conservation Act (42 U.S.C. 6240(a), (b), and (d)) shall cease to apply to the reserve.

"(b)(1) Part B of title I of the Energy Policy and Conservation Act (42 U.S.C. 6215 et seq.) is amended by adding after section 167 the following new section 168:

'DEFENSE PETROLEUM INVENTORY

'SEC. 168. (a) Notwithstanding any other provision of this part, the Secretary may acquire or construct, operate and maintain storage and related facilities to meet petroleum product requirements of the Department of Defense, and may acquire and store therein a Defense

Petroleum Inventory of crude oil. This acquisition and storage shall be in addition to any acquisition or storage of crude oil for the Strategic Petroleum Reserve required by any other law, and crude oil acquired and stored under this section shall not be counted as part of the Strategic Petroleum Reserve. In carrying out the functions authorized by this section, the Secretary may exercise any authority available under this part.

'(b) The Secretary shall obligate the United States' share of funds available in the Naval Petroleum Reserve Lease Proceeds Special Account created by section 16006 of the Naval Petroleum Reserve Leasing Act for the acquisition of 10,000,000 barrels of crude oil for the Defense Petroleum Inventory. Until the acquisition of 10,000,000 barrels of crude oil for the Defense Petroleum Inventory has been completed, the Secretary shall dedicate to the Defense Petroleum Inventory, crude oil contained in the Strategic Petroleum Reserve in sufficient quantities to maintain the Defense Petroleum Inventory at a level determined by multiplying 10,000,000 barrels times the percentage of the United States' interest in the Naval Petroleum Reserve Numbered 1 leased under Naval Petroleum Reserve Leasing Act. Any crude oil so dedicated shall be considered to remain in storage for the purposes of any law relating to the rate of fill of the Strategic Petroleum Reserve.

'(c) Notwithstanding any other provision of this part, upon the request of the Secretary of Defense, crude oil acquired for or dedicated to the Defense Petroleum Inventory shall be drawn down and distributed by the Secretary to, or on behalf of, the Department of Defense for use, sale, or exchange. Crude oil in the Defense Petroleum Inventory may be drawn down and distributed, used, sold, or exchanged, without regard to--

'(1) whether the crude oil has been commingled with petroleum products of the Strategic Petroleum Reserve;

'(2) the requirements of this part concerning drawdown of the Strategic Petroleum Reserve; or

'(3) otherwise applicable Federal contracting statutes and regulations.

The Secretary of Energy shall exercise the authority provided by this subsection in a manner which does not adversely affect drawdown of the Strategic Petroleum Reserve.

'(d) Upon the request of the Secretary of Defense, and subject to the availability of funds from the Department of Defense, the Secretary shall acquire and store in the Defense Petroleum Inventory crude oil to replace crude oil drawn down under subsection (c).

'(e) An amendment to the Strategic Petroleum Reserve Plan relating to the exercise of this authority shall not be required.

'(f) The Department of Defense shall reimburse the Department of Energy for--

'(1) drawdown and distribution services provided under this section, in amounts that the Secretary determines to be reasonable;

'(2) all costs of acquiring crude oil for the Strategic Petroleum Reserve to replace crude oil drawn down and distributed under subsection (c); and

'(3) all costs of acquiring and storing in the Defense Petroleum Inventory any crude oil in excess of the initial 10,000,000 barrels acquired for it or dedicated to it.

'(g) Crude oil acquired for the Defense Petroleum Inventory under subsection (a) shall be transferred to the Strategic Petroleum Reserve, pursuant to subsection (f)(2), in reimbursement on a barrel-for-barrel basis for the cost of replacement petroleum products acquired for the Strategic Petroleum Reserve.'.

"(2) The Table of Contents of the Energy Policy and Conservation Act is amended by inserting after the entry for section 167 the following:

'SEC. 168. Defense Petroleum Inventory.'.

"SEC. 16006. NAVAL PETROLEUM RESERVE LEASE PROCEEDS SPECIAL ACCOUNT AND REVENUE SHARING WITH THE STATE OF CALIFORNIA.

"(a) There is established in the Treasury of the United States a fund called the 'Naval Petroleum Reserve Lease Proceeds Special Account' (referred to as the 'Special Account') which shall be available to the Department of Energy without fiscal year limitation to carry out the purposes, functions, and powers authorized by this title. In order to carry out the purposes of this section, the Secretary shall notify the Governor of the State of California of the Secretary's intention to conduct a leasing action or to enter into a lease under this title.

"(b) There shall be deposited in the Special Account all proceeds realized under this title from the lease of all or any part of the United States' interest in Naval Petroleum Reserve Numbered 1, including bonus and royalty payments, rents, and interest.

"(c) 50 percent of the proceeds received from royalty and from those interest payments described in section 16002(g)(3) of this title and 7 percent of the bonus payments from Naval Petroleum Reserve Numbered 1 under this title shall, notwithstanding any other provision of law, be paid to the State of California (to be credited by the State in accordance with California Public Resources Code, section 8711, as amended from time to time, and allocated in the manner provided in California Statutes 1988 ch. 985, section 3, as amended from time to time). The total portion of the proceeds accruing to the State of California from the bonus payments shall be paid to the State of California in seven annual payments, beginning one year from the date that the Federal Government receives the first installment of the bonus payments from the lessee. No interest shall be due on these amounts to the State. Each of the seven annual payments shall be equal to one seventh of the total lease bonus proceeds due to the State.

"(d) The Secretary may make expenditures from the Special Account without further appropriation and without fiscal year limitation, but within such specific directives or limitations as may be included in appropriations Acts and subject to the requirements of subsection (c), for any purposes necessary or appropriate to carry out section 168(b) of the Energy Policy and Conservation Act or to satisfy obligations related to the lease of Naval Petroleum Reserve Numbered 1 as specified in section 16002(c)(1).

"(e)(1) Upon a written notification from the Secretary to the Secretary of the Treasury that the Special Account contains funds in excess of the amounts considered necessary to fulfill the purposes specified in subsections (c) and (d), excess funds specified by the Secretary may be transferred from the Special Account to the miscellaneous receipts account of the Treasury of the United States. In the event funds are no longer required to fulfill the purposes specified in subsections (c) and (d), the Special Account shall be abolished and all remaining funds credited to the miscellaneous receipts account of the Treasury of the United States.

"(2) Following abolition of the Special Account under subsection (e)(1), proceeds realized under this title from the lease of all or any part of the United States' interest in Naval Petroleum Reserve Numbered 1 shall be deposited in the miscellaneous receipts account of the Treasury of the United States; except for the portion of royalty, interest and bonus payments specified in subsection (c) to be paid to the State of California, which shall continue to be paid to that State regardless of the status of the Special Account.

"(f) The Secretary may collect lease proceeds on behalf of any private owner of Naval Petroleum Reserve Numbered 1 and may pay the owner its share of lease proceeds.

"SEC. 16007. CONGRESSIONAL CONSULTATION.

Compliance with the procedures specified in sections 16002(b) and (d) of this title shall be considered to satisfy the requirements of sections 7431(a) and 7431(b) of title 10, United States Code.

"SEC. 16008. EFFECT ON SCHOOL LANDS GRANT.

"(a) Subject to the provisions of this section, the authority to lease under this title extends to sections 16 and 36 within Naval Petroleum Reserve Numbered 1.

"(b) A payment may be made under section 16006(c) of this title only after the State of California, on behalf of all party plaintiffs, dismisses without prejudice, either by stipulation or motion, the lawsuit filed by the State against the United States and certain agency officials in November, 1987 in the United States District Court for the Eastern District of California (Docket No. CV-F-87-665-EDP).

"(c) Any rights of the State of California under section 6 of the Act of March 3, 1853 (Chapter CXLV; 10 Stat. 246) to sections 16 and 36, Township 30 South, Range 23 East Mount Diablo Base and Meridian, located within Elk Hills, including all rights to indemnity lands under Revised Statutes 2275 and 2276 (43 U.S.C. §§ 851 and 852) shall be --

"(1) abated during such time as the State of California is receiving the payments described in section 16006(c) of this title, and

"(2) extinguished in full upon the receipt by the State of California of the seventh and final payment of its share of the lease bonus payments described in section 16006(c) of this title;

provided that any extinguishment of rights described in paragraph (2) shall not prejudice or otherwise adversely affect the right of the State of California to receive the payments described in section 16006(c) of this title.

"(d) During the period beginning with the date of enactment of this subtitle and ending upon the date of the extinguishment of the rights of the State of California in the manner provided in subsection (c)(2), the limitation periods under any statutes of limitations applicable to actions in respect of the rights of the State described in subsection (c) shall be tolled; provided, however, that nothing in this subsection (d) shall be construed as affecting during the period prior to the date of enactment of this subtitle any limitations period under any statute of limitations applicable to actions in respect of the rights of the State described in subsection (c).

"(e) Upon the cancellation, termination, or forfeiture of any lease of Naval Petroleum Reserve Numbered 1 authorized under this subtitle, in the event that the Secretary fails to enter into a new lease within twenty four months after the date of such cancellation, termination, or forfeiture, the State of California shall be entitled to receive seven percent of any revenues derived by the United States from Naval Petroleum Reserve Numbered 1 during the period following expiration of such twenty-four month period until a new lease is entered into by the Secretary; *provided* that any revenues received by the State of California under this subsection (e) shall be credited against any royalties that otherwise would become due to the State under section 16006(c) of this title upon a subsequent lease of Naval Petroleum Reserve Numbered 1."

"SEC. 16009. CONFORMING AMENDMENTS.

"(a) Section 501 of Public Law 101-45 (103 Stat. 103) is deemed modified to the extent inconsistent herewith.

"(b) Section 7422(a) and (b) of title 10, United States Code, are amended to read as follows:

'(a) The Secretary, directly or by contract, lease, or otherwise, shall explore, prospect, conserve, develop, use, and operate the naval petroleum reserves in his discretion, subject to the provisions of this chapter, except the authority to lease is not extended to Naval Petroleum Reserve Numbered 3.

'(b) Except as otherwise provided in this chapter, particularly subsection (c) of this section, and in the Naval Petroleum Reserve Leasing Act, the naval petroleum reserves shall be used and operated for--

'(1) the protection, conservation, maintenance, and testing of those reserves; or

'(2) the production of petroleum whenever and to the extent that the Secretary, with the approval of the President, finds that such production is needed for national defense purposes and the production is authorized by a joint resolution of Congress.'.

"(c) Section 7422(c)(1)(B) of title 10, United States Code, is amended to read as follows:

'(B) to produce such reserves at the maximum efficient rate consistent with sound engineering practices.'.

"(d) Sections 7422(c)(1)(C), 7422(c)(2), and 7426(b), (c), (d), and (e) of title 10, United States Code, are repealed.

"(e) Sections 7430(a) of title 10, United States Code, is amended to read as follows:

'(a) In administering the naval petroleum reserves under this chapter, except for those reserves covered by leases executed pursuant to the Naval Petroleum Reserve Leasing Act, the Secretary shall use, store, or sell the petroleum produced from the naval petroleum reserves and lands covered by joint, unit, or other cooperative plans as provided in this section.'.

"(f) Section 7430(b)(1) of title 10, United States Code, is amended by striking 'paragraph (2) and notwithstanding any other provision of law' and inserting 'subsection (a) and paragraph (2)'.

"(g) Section 7430(f) of title 10, United States Code, is amended to read as follows:

'(f) The consultation and approval requirements of section 7431(a)(3) are waived for contracts to sell petroleum produced from Naval Petroleum Reserves Numbered 1, 2, and 3, and for contracts to sell petroleum from the Naval Oil Shale Reserves which is produced for their exploration, protection, conservation, maintenance, and testing.'.

"(h) Section 7430(l)(1) of title 10, United States Code, is amended to read as follows:

'(1) The Secretary, at the request of the Secretary of Defense, may provide any portion of the United States share of petroleum to the Department of Defense for its use, exchange, or sale in order to meet petroleum product requirements of the Department of Defense.'.

"(i) Section 7431(a) of title 10, United States Code, is amended by adding 'Except for actions taken pursuant to the Naval Petroleum Reserve Leasing Act,' at the beginning of the subsection.

"(j) Section 7431(b) and (c) of title 10, United States Code, are amended by striking "During the period of production authorized by section 7422(c) of this title, the' and inserting 'The'.

"(k) Section 7433(b) of title 10, United States Code, is amended to read as follows:

'(b) Except as provided in the Naval Petroleum Reserve Leasing Act, all money accruing to the United States from lands in the naval petroleum reserves shall be covered into the Treasury.'."

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4/8/91

Canadian Embassy Ambassade du Canada

501 Pennsylvania Avenue, N.W.
Washington, D.C. 20001

April 15, 1991

The Honourable J. Bennett Johnston
Chairman
Committee on Energy and Natural Resources
United States Senate
364 Dirksen Senate Office Bldg.
Washington, D.C. 20510-1902

Dear Senator Johnston,

I am writing to convey my government's view that two provisions of S. 341, the "National Energy Security Act of 1991", and one provision of the Gas Policy Reform bill (S. 662), would violate the obligation of the United States under our Free Trade Agreement not to discriminate against Canadian products.

Section 7001 of S. 341 would require oil importers, but not domestic producers, to supply petroleum products free of charge to the Strategic Petroleum Reserve. Section 14111(d) would restrict the uranium to be used for overfeed to U.S. uranium. Section 1024 of the Gas Policy Reform bill would require that the competitive impact of natural gas imports on U.S. producers be taken into account in the regulatory approval of those imports. In each case, Canadian products would face discriminatory treatment in a manner contrary to the Free Trade Agreement obligations of the United States.

In our view there is no national security justification for measures which discriminate against imports from Canada.

I would urge that the Committee reject any proposal which would damage our mutually beneficial and expanding trade in energy products.

Yours sincerely,

D.H. Burney

D.H. Burney
Ambassador

Statement on Behalf of

THE SOCIETY OF INDEPENDENT GASOLINE MARKETERS OF AMERICA

Before the Senate Committee on
Energy and Natural Resources

Regarding Title VII of S. 341,
The National Energy Security Act

Collier, Shannon & Scott
Washington, D.C.

Statement on Behalf of

THE SOCIETY OF INDEPENDENT GASOLINE MARKETERS OF AMERICA

Before the

U.S. SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

I. INTRODUCTION

On behalf of the Society of Independent Gasoline Marketers of America ("SIGMA"), this statement is submitted in response to the Senate Committee on Energy and Natural Resources' solicitation of comments regarding Title VII of S. 341, the National Energy Security Act of 1991. SIGMA is a national trade association comprised of over three hundred independent gasoline marketers and private brand chain retailers of motor fuels. SIGMA's members market refined petroleum products in all 50 states, and their sales account for approximately 15 to 20 percent of the U.S. retail market for motor gasoline.

Independent marketers and chain retailers neither produce nor refine crude oil and are entirely dependent upon third parties for their sources of supply. The ability of marketers and retailers to price competitively depends upon the availability of gasoline priced at a level that permits them to make their operating efficiencies relevant at the retail level. Access to foreign petroleum products is necessary to ensure that products are available to marketers at competitive wholesale prices.

The so-called Strategic Petroleum Reserve ("SPR") "import set-aside" proposal contained within Title VII of S. 341 is functionally no different than an oil import tax. Taxes on imported oil impede competition at the retail level of the gasoline market and create a disincentive for domestic refiners to deal on a competitive basis with their marketer and retailer competitors. In addition, oil import taxes are economically inefficient and may violate U.S. international obligations. Moreover, the set-aside proposal itself is of questionable constitutionality. For these and other reasons, any proposal that would create a price differential between imported and domestic crude oil and petroleum products, such as the oil import set-aside, should be rejected in favor of a more efficient funding alternative.

II. DESCRIPTION OF THE U.S. INDEPENDENT GASOLINE MARKETER

Independent gasoline marketers, such as SIGMA members, have been recognized as being among the world's most efficient retailers of motor fuels. These companies historically have been the most innovative and price-competitive segment of the retail motor fuels market.

Independent marketers compete directly with one another as well as with the downstream marketing and retailing operations of refiners. Indeed, the impact of independent marketers on price competition in the marketplace in general has been extremely beneficial. See Marathon Oil Co. v. Mobil Corp., 669 F.2d 378, 382 (6th Cir. 1981). Because of greater efficiencies and superior systems of cost controls, independent marketers have played a critical role in inducing price competition in the domestic market for gasoline. In addition, independent marketers supply most of the refined products in many of the geographic areas abandoned by major refiners. Thus, consumers benefit from independent marketers both in terms of price and product availability.

Independent marketers must rely upon the pro-competitive effects generated by relatively unrestricted access to finished gasoline and gasoline blendstocks of foreign manufacture. This potential alternative supply constitutes the principal incentive for integrated domestic refiner-marketers to sell competitively-priced product to their marketer-competitors. The fewer restrictions on foreign supply, the greater the incentive for domestic refiner-marketers to sell competitively-priced products to independent marketers.

The systems of cost control that allow the independent marketer to compete with the large integrated oil companies -- and thereby better service the consumer -- apply only if independent marketers can obtain petroleum products at prices that enable them to make their superior marketing efficiencies relevant in the retail market. Access to competitively-priced imported oil promotes greater price competition in the wholesale market, thereby resulting in enhanced competition in the retail market. In short, free and open trade in crude oil and petroleum products benefits the retail consumer by promoting price competition at the retail outlet.

III. THE SPR SET-ASIDE IS THE FUNCTIONAL EQUIVALENT OF AN OIL IMPORT TAX

The SPR set-aside proposal would necessarily result in an increase in the domestic price of all imported oil. Oil importers would raise their prices on such imported oil by an amount to offset the cost of the set-aside. The cost of all domestic energy would rise accordingly as domestic oil producers would raise their prices to a level equal to or just below the price of imported oil. It has been estimated that, at today's prices, a three-percent set-aside requirement would have the same effect as a 35-cent per barrel oil import tax; a nine-percent set-aside requirement would be equal to an oil import tax of greater than $1 per barrel.

In considering the estimated cost of the set-aside proposal, it should also be noted that any proposal that places a higher rate of tax on imported oil would have serious macroeconomic effects. In fact, imposition of an oil import tax or its equivalent would be much more cost inefficient than an end-user tax on gasoline. Yet, when an increase in the gasoline excise tax was debated last session as a means of reducing the federal budget deficit, it received considerable opposition based on the perceived inefficiencies of such a measure.

In recent years, the United States Congress has rejected the oil import tax concept by substantial margins. There exists widespread opposition to the oil import tax by energy users, the electric utility industry, the petrochemical industry, the transportation industry, and household consumers. This opposition is grounded in sound economic reasoning and cost/benefit analysis which indicates that the economic benefits of a fee are far outweighed by the economic disadvantages.

The SPR set-aside proposal, like an oil import tax, would unfairly burden the low and middle-income energy users of the Northeastern and Mid-Atlantic states who consume a much greater quantity of petroleum than any other region of the country. Nationally, industries that rely heavily on energy in the manufacturing process would be placed at a competitive disadvantage vis-a-vis their international competitors as a result of the increased cost associated with the oil import tax or its equivalent. Moreover, the weakening of the independent marketing segment of the retail market for gasoline would damage all consumers.

The SPR set-aside proposal would also be difficult, if not impossible, to administer. The program would require the creation of a bureaucracy to monitor and enforce the contributions of crude oil and petroleum products from domestic refiners.

Furthermore, the suggested system of exchanges, "paper swaps," credits, and payments would require government regulation costs and unintended consequences that cannot fully be assessed.

IV. THE SET-ASIDE MAY BE UNCONSTITUTIONAL AND VIOLATIVE OF U.S. INTERNATIONAL OBLIGATIONS

The SPR set-aside proposal would impose what could be considered unreasonable restrictions on the private use of energy by confiscating refiners' property without proper compensation and by initiating a program that is essentially an oil import user fee. Such action could be considered a taking and violative of the Fifth Amendment to the United States Constitution.

The fact that the Energy Policy and Conservation Act authorizes the set-aside does not make it constitutional. The proposed set-aside has never before been implemented and a constitutional challenge would almost certainly follow if it were. Moreover, a variety of organizations, both government and private, including the Department of Energy and the American Petroleum Institute, among others, have questioned its validity.

The set-aside proposal may also violate U.S. obligations under the General Agreements on Tariffs and Trade and invite retaliation by our trading partners. The set-aside would be especially inimical to U.S. relations with its most important Western Hemisphere sources of oil supply: namely, Canada, Mexico, and Venezuela. The validity of such a proposal under the United States-Canada Free Trade Agreement ("FTA") is questionable at best. The set-aside may also jeopardize on-going negotiations between Mexico and the United States regarding a North American FTA and would send the wrong message to Venezuela, an important supplier and strategic ally that was instrumental in making up for the shortfall in supply during the Persian Gulf War.

V. CONCLUSION

The continued filling of the SPR is undoubtedly in the national interest. The challenge before Congress today is to conceive of the most cost-effective means, from a macroeconomic perspective, by which to accomplish this goal.

The SPR set-aside proposal is discriminatory in that it creates a price differential between imported and domestic crude oil and petroleum products. Although the concept of requiring oil importers to set aside a percentage of their imports may appear benign to some, the effect is no different than imposing an oil import tax. An oil import tax would raise prices on all energy in an amount equal to the per barrel cost of the set-aside.

Independent gasoline marketers would be especially vulnerable to the price differential. Independent marketers rely on the pro-competitive effects generated by unrestricted access to imported finished gasoline and gasoline blendstocks. Removal of this incentive to price competitively would have a particularly harsh effect on independent marketers, who, unlike large, integrated oil companies, would be incapable of absorbing or redistributing the additional cost. Moreover, the imposition of such a measure would be anti-competitive and costly to consumers; by weakening the independent segment of the retail gasoline market, a long-term cost increase would likely occur at both the refining and marketing level.

The wisdom of this policy is especially suspect at present while the country is in the midst of a recession. Many economists believe the petroleum price spike of the fall of 1989 was a contributing factor to the current recession. An oil import tax or its equivalent would, in effect, institutionalize a part of that price spike into the current price for oil. United States manufacturers and motorists would suffer accordingly.

Oil import taxes have been considered and rejected by Congress on countless occasions. The rationale for rejecting the oil import tax applies equally to the set-aside proposal. Oil import taxes are regressive, inefficient, and discriminatory and, in all likelihood, violate U.S. international obligations. Moreover, the set-aside itself is of questionable constitutionality.

SIGMA believes that there are many proposals before this Committee, including other provisions within S. 341, that could enhance energy security. The oil import set-aside, however, is not one of them and should be rejected.

April 9, 1991

National
Council of
Farmer
Cooperatives

Honorable J. Bennett Johnston
Chairman
Energy and Natural Resources Committee
U.S. Senate
Washington, DC 20510

RE: Comments--National Energy Strategy (S. 341, et al)

Dear Mr. Chairman:

The National Council of Farmer Cooperatives would like to take this opportunity to commend you and Senator Malcolm Wallop for working so diligently together in crafting S. 341, The National Energy Security Act of 1991. This legislative package for the most part approaches the difficult energy challenges which lie before our nation in the coming decades, with balanced and often creative solutions.

The National Council is pleased to offer comments on selected provisions in both S. 341 and the Administration bill (S. 570) via the enclosed statement. We would reques that our statement be incorporated as part of the record o the National Energy Strategy hearings.

Sincerely,

Wayne Boutwell

Wayne A. Boutwell
President

cc: The Honorable Malcolm Wallop

Enclosure

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Serving America's Family Farmers

National
Council of
Farmer
Cooperatives

THE NATIONAL ENERGY SECURITY ACT OF 1991

S. 341, et al

Comments Submitted
to the
Committee on Energy and Natural Resources
U.S. Senate

by the
National Council
of
Farmer Cooperatives

April 9, 1991

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SUMMARY POSITION

The Chairman and Senator Malcolm Wallop, ranking minority member, are to be commended for working so diligently together in crafting S. 341, The National Energy Security Act of 1991. This legislative package for the most part approaches the difficult energy challenges which lie before our nation in the coming decades, with balanced and often creative solutions.

The National Council of Farmer Cooperatives (National Council) is generally pleased by the careful blending of (1) measures to increase domestic production of conventional energy sources, and (2) provisions which emphasize conservation and development of renewable energy sources. Through removal of excessive barriers and targeted incentives, most measures are designed to encourage both producers and consumers of energy to respond to appropriate market signals with a minimum of government interference.

However, we must respectfully **take exception to the proposed "Oil Security Premium"** in Title VII. Although not addressed in S. 341, we would also like to take this opportunity to raise concerns about **deficiencies in the Administration's current Strategic Petroleum Reserve (SPR) drawdown policy**, which we would recommend be remedied as part of any comprehensive energy strategy legislation which may be enacted into law: (1) Limit universe of bidders to U.S. refiners; and (2) Dedicate portion of 10-percent directed sales to meet minimum needs of cooperative refiners.

Our views in brief concerning other selected provisions of both S. 341 and the Administration bill (S. 570) are as follows:

+ Economic Deregulation of Oil Pipelines (Title III, Subtitle C, S. 570)--**Strongly Oppose**

+ Open ANWR to E&P (Title IX, S. 341)--Support

+ Domestic O&G Production Financial Incentives (Administration's NES Report, p. 82)--Support, urge restoration of depletion allowance to all new & enhanced recovery production

+ Electric Utility Reform (Title XV, S. 341)--Oppose, unless also provide open access to large-volume volume agricultural and other industrial electricity customers

+ Harmonization of Energy Supply and Environmental Objectives (Administration's NES Report, pp. 85; 144-5)--Support

INTEREST OF THE NATIONAL COUNCIL

The National Council of Farmer Cooperatives is a nationwide association of cooperative businesses which are owned and controlled by farmers. Its membership includes over 100 major agricultural marketing, supply and credit cooperatives, plus 32 state councils of farmer cooperatives. National Council members handle practically every type of agricultural commodity produced in the U.S., market these commodities domestically and around the world, and furnish production supplies and credit to their farmer members and patrons. The National Council represents about 90 percent of the nearly 5,000 local farmer cooperatives in the nation, with a combined membership of nearly 2 million farmers.

Farmers and their cooperatives are critically dependent on petroleum, natural gas and electricity. In addition, the National Council represents supply cooperatives which own and operate five modern refineries with a combined capacity of 220,000 barrels per day. Of that capacity, about 85 to 90 percent is gasoline, diesel fuel and heating oil. Our member cooperatives market petroleum products in more than 40 states and currently supply about 39 percent of all on-farm fuel needs, as well as the fuel needs of much of rural America.

Farmer cooperative operations represent the only segment of the oil industry in which the consumers of its products are also its owners. This feature carries with it a unique accountability and commitment.

TITLE VII.--OIL SECURITY PREMIUM

The Oil Security Premium created in Title VII of S. 341 would require oil importers to provide a percentage of their total oil imports sufficient to (1) fill the SPR at a rate of 220,000 barrels per day; and (2) meet the worldwide petroleum product needs of the U.S. Department of Defense. The program would begin in FY 1992. It is estimated that the share would likely run in the 9-10 percent range. Importers would not receive any compensation for their required contributions.

Genesis of Proposal:

In opening remarks at the March 12, 1991 Committee hearing on Title VII, recent events in the Gulf region were cited as highlighting chronic instabilities that have periodically threatened our oil supplies and necessitated both the creation of the SPR and a continuing, costly U.S. military presence in that region.

The National Council certainly concurs with this characterization of our continuing vulnerability to foreign oil supply disruptions. That is why we have consistently supported an aggressive SPR fill program and development of an effective drawdown policy for use during times of emergency, including at times when others advocated straying from this course of action.

Essentially three related premises were raised at the hearing as primary justification for creation of the proposed Oil Security Premium:

(1) Those who import oil into the United States are primarily responsible for the vulnerability to foreign oil disruptions;

(2) Importers are more vulnerable to the adverse consequences of foreign oil disruptions than are those who utilize domestic oil, and thus benefit more from SPR and defense expenditures; and

(3) Importers are not paying a fair share of the SPR and Defense costs that are required to respond to this vulnerability.

The National Council must respectfully disagree with both the proposed solution and the premises upon which it is purportedly founded. Simply stated, our view is as follows:

(1) All Americans are equally vulnerable to the adverse consequences of foreign oil disruptions and military aggression;

(2) All Americans should therefore continue to contribute equitably to the necessary costs of maintaining these vital national security institutions; and

(3) Any attempt to impose greater culpability and financial burdens directly on those entities which happen to import oil in responding to the demands of domestic consumers is misdirected.

All Consumers Benefit, All Should Pay:

Whether sound policy or not, our nation's economic engine has thrived in large part due to the worldwide abundance of reasonably-priced oil. This abundance would not be possible absent production elsewhere--in particular the Gulf region. Much of the economic growth we have experienced over the past several decades would not have been realized without oil from foreign sources. All consumers have benefited, not just those who necessarily been obligated to import oil in order to fulfill the demands of their customers.

Perhaps an argument can be made that prices have not reflected the vulnerability to uncertain supplies and price fluctuations that can accompany periodic political instabilities in some foreign oil producing regions. But this is by no means any justification for placing a disproportionate burden of the resultant "insurance" policies upon those who must import to meet the energy demands of American consumers.

Furthermore, the underlying rationale for the Oil Security Premium specifically cites vulnerability to disruptions in the Gulf region. Yet the program would assign equal burdens to all importers, even if they import from non-Gulf sources. Even if should one accept this rationale, surely an importer of Canadian oil, for example, should not shoulder equal blame.

Oil is a fungible commodity. An imported barrel very quickly loses its distinguishability from a domestic barrel. It's essentially impossible to determine the source of a gallon of gasoline when it goes into the tank of a consumer's automobile.

It is reasonable to assume that most if not all importers would prefer to have access to competitively priced domestic oil to meet the needs of their customers. But oil is imported not by choice, and not without regard to the inherent potential risks associated with dependence on foreign oil. Rather oil is imported because there is not enough domestic oil to go around under any reasonable scenario to meet domestic demand.

The reality is that this nation's appetite for oil long ago outstripped our ability to produce it domestically. Even if entities who now import oil chose to bid for and purchase domestically produced oil instead, the practical end result would likely be higher prices, with possibly different importers of record. The need for imported oil and vulnerability to foreign supply disruptions would remain.

Others have raised significant concerns of a more technical nature, including competitive distortions in the refining and petrochemical industries, objections under GATT and the Canadian Free Trade Agreement and the possible creation of a complex new implementing bureaucracy. The National Council shares the thrust of many of those concerns. However, we believe that even if such concerns could be remedied, the fundamental principal that all should contribute equitably to the financing of our nation's SPR and national defense would still rule against the proposed Oil Security Premium.

Opposition to Oil Import Fee:

There are some who would interpret the Oil Security Premium as also targeting another, somewhat interrelated policy objective:

> Reducing dependence on foreign oil sources by stimulating domestic oil exploration and production, via an increase in the effective price offered for domestic oil.

The Oil Security Premium would likely operate in a manner essentially identical to an oil import fee. The anticipated 10-percent contribution of oil by importers would equate to a 10-percent oil import fee. Depending upon which analysis one wishes to believe, this would translate into an increase in prices offered for domestic oil of from 5 to 10 percent, thereby offering fresh economic stimulus to domestic producers.

While we support the goal of reducing dependence on foreign oil, the National Council remains philosophically opposed to an oil import fee or other similarly configured energy tax as a solution. The adverse impacts on the economy, as well as disproportionate and regressive burdens on rural America and other segments of society are well documented.

As independents who control little domestic crude oil, farmer-owned cooperatives necessarily turn to foreign sources for much of their crude oil needs in supplying farmers and other rural consumers with refined petroleum products. Thus, the proposed Oil Security Premium would fall disproportionately upon farmer-owned cooperatives, with the resultant adverse competitive distortions and financial burdens ultimately being borne by farmer-owners.

SPR DRAWDOWN POLICY DEFICIENT

The National Council's concerns about the efficacy of the Oil Security Premium proposal are compounded by our conviction that SPR policy as it is presently structured contains significant deficiencies, which greatly diminish the likely effectiveness of the SPR in mitigating adverse consequences of future disruptions on the farmer cooperative community and rural America.

The National Council would submit that the bottom line in determining the success of SPR policy in responding to an oil supply disruption is whether refined petroleum products reach consumers in a manner that is both timely and least disruptive to normal market operations. This can be achieved only by insuring that SPR crude oil flows expeditiously to U.S. refineries serving all regions, early in a supply disruption. Significant design deficiencies in the existing SPR drawdown plan run counter to that operational goal.

Universe of Bidders:

First, the SPR auction process is structured so that it invites a **wide-open universe of potential bidders.** This means that participants with little or no experience in the complex workings of the oil refining and distribution sector--including foreign governments; federal, state and local government entities; large end users of refined products (e.g., airlines, railroads, utilities, petrochemical firms, Dept. of Defense); and investors--could be attempting to learn the business at the worst possible time, in the midst of a disruption.

Most such entities have need for a particular refined product, not crude oil, and have no experience in the complex business of refining and distributing petroleum. Foreign governments and investors have investment or other motives unrelated to the need for petroleum products. Their participation in SPR bidding would assuredly result in additional distortions and costly delays in a system already stressed by shortages, to the detriment of American consumers and national policy objectives. Costly distortions to the marketplace would likely occur, and consumers would ultimately bear the heavy costs of this "learning experience."

The National Council would recommend the following targeted modification:

> **Limit the eligible universe of bidders to U.S. petroleum refineries, and those U.S. petroleum marketers who can document their bid by a valid crude oil processing agreement with a demonstrated capacity to process the same crude oil on a timely basis.**

Address Regional Shortages Through Second Pool:

Second, while we recognize and endorse the important role that SPR oil can serve in offsetting overall shortages, we believe regional shortages are more likely to occur, particularly in rural areas. Such regional shortages have historically set the tone for policy responses, often ill-advised, during times of shortages. Regional shortages must be addressed if SPR policy is to be effective.

As independent refiners, cooperatives are likely to experience disruption of a greater proportion of crude oil supplies. In addition, cooperative refiners are essentially located in inland, rural regions which are generally inaccessible to SPR storage facilities and pipelines and terminals connecting those facilities to the transportation infrastructure. Gulf Coast refineries possess an inherent advantage vis-a-vis the inland refineries which goes beyond the normal transportation advantages associated with access to imported crude oil.

These two factors in combination make it less likely that farmer cooperatives will be able to bid successfully for crude oil in the present wide-open auction process. Even when successful, it will prove difficult to move SPR oil to our members' facilities, except through exchanges, if available. In general, other suppliers will be unable to step in and offset any resulting refined product shortages in rural markets.

To address these problems, the National Council would recommend the following:

> **Provide for the sale and distribution of SPR crude oil in two pools, with the second pool dedicated in part to meet minimum needs of farmer cooperatives.**

DOE has discretionary authority to implement this change under the existing Plan Amendment No. 4. However, no changes are contemplated, and we would urge the Committee to legislate the modification.

Experience Gained From SPR Sales:

The Department of Energy is to be commended for the overall efficiency of its conduct in the two sales of SPR oil which have occurred in the past year. Farmer cooperatives participated in both instances, and we found the program to be generally well run, with DOE staff responsive to concerns raised by oil industry participants. This positive experience was in significant part due to the fact that only established entities in the petroleum industry participated.

The list of participants in both (1) the SPR test sale in the fall of 1990 and (2) the sale instituted at the onset of hostilities in the Kuwaiti theater essentially mirrors the first National Council recommendation.

In each instance, the actual list of participants proscribes a distinctly limited and defined universe of bidders who are all established in the domestic petroleum refining and marketing business, and not the much broader universe of bidders that would likely participate in a true oil supply crisis. Most own domestic refining capacity. As such, they are well equipped to expedite stated goals of SPR policy.

Neither sale occurred in the true crisis environment that would prompt many non-petroleum entities to attempt to participate. In spite of prevailing Middle East uncertainties, it was clear to all parties that domestic inventories of both crude oil and refined product were generally at high levels. Participants were not bidding to replace lost supplies, but more to become familiar with the system and to be supportive of the Department's request for industry participation.

Thus, the mix of participants in these two sales is not reflective of the much broader universe likely to rush to the SPR bidding table under the present plan in the midst of a true crisis.

OTHER PROVISIONS

Oil Pipeline Deregulation:

The National Council strongly opposes Title III, Subtitle C of the Administration bill (S. 570), which provides for economic deregulation of oil pipelines.

The National Council opposes deregulation of rates and practices of oil pipeline companies, except in those markets where competitive alternatives have clearly been shown to exist. In most instances, the only effective means of competition is pipeline-to-pipeline. Large segments of the petroleum industry serving rural areas are captive shippers, where no viable alternative in transporting petroleum exists. Our members' experience leads us to conclude that effective competition is clearly the exception rather than the rule.

Unreasonable increases in pipeline rates to captive shippers (and ultimately petroleum consumers) would adversely impact the entire agricultural economy and intensify inflationary pressures on all consumers through higher prices for food as well as fuels. Therefore, the National Council believes that petroleum shippers must continue to have an appropriate forum to challenge economically unwarranted increases in pipeline tariffs.

Revitalizing Domestic Oil & Gas Production:

The National Council believes rational policies can and must be developed to open frontier areas to oil and gas development in a fashion which protects the environment. By far the largest potential remaining reserves lie in such areas, and they must be developed to serve near-term needs as the nation engages in the search for alternatives over the longer term.

We are pleased that S. 341 addresses this vital need regarding the Alaska National Wildlife Refuge (ANWR) in Title III. We would hope that outstanding issues concerning Outer Continental Shelf (OCS) leasing may also be resolved and environmentally responsible development begun.

Financial incentives comprise a necessary and important ingredient in the final recipe for enhancing domestic energy production. The Administration's National Energy Strategy (NES) Report proposes extending limited incentives which were instituted in 1989 and 1990. While these actions represent modest but important steps, the National Council would urge Congress and the Administration to explore other fiscal policy options for enhancing stimulating domestic production.

Domestic Refining Capacity:

The National Council believes strong domestic refining capability must be maintained if the nation's future petroleum product needs are to be met, especially during times of disruption when Strategic Petroleum Reserve (SPR) oil must be converted into product. A large number of refineries were forced to shut down for a number of reasons in the early eighties. Farmer cooperatives were forced to shut down or sell three refineries. Excess domestic refining capacity is now a thing of the past.

The Administration specifically recognizes the significant reduction which has occurred in domestic refining capacity during the past decade, as well as extensive investments necessitated by requirements in the Clean Air Act Amendments (NES Report, p. 85). A two-year study by the National Petroleum Council on the domestic refining industry has been requested.

We would urge both the Congress and the Administration to pursue policies designed to maintain a viable domestic refining industry, structured to meet both national and regional needs. According to a 1986 NPC study, many regional refiners, including those owned by cooperatives, each have their own important niche in serving local and specialty markets with minimal transportation costs (NPC report, U.S. Petroleum Refining, 1986).

Electric Utility Reform:

The National Council opposes reform of the Public Utility Holding Company Act (PUHCA) as proposed in Title XV of S. 341, unless the provision is modified to provide a necessary balance between generators and end users of electricity. In exempting affiliates of utilities which generate wholesale electricity, there are no effective measures to protect consumers from serious potential abuses.

Balance can be accomplished at least in part by providing open access to large volume agricultural and other industrial users of electricity. The principle is somewhat similar to the competitive balance successfully implemented through contract carriage of natural gas.

Harmonization of Energy and Environmental Policies:

In at least two different sections of its final NES Report (pp. 85; 144-5), the Administration calls for "harmonization" of energy and environmental policies, including analysis of energy policy impacts as a part of future environmental rulemaking. It is our understanding that the Environmental Protection Agency (EPA) may be objecting to this policy initiative, arguing that it would "hinder their implementation of environmental policy."

The National Council applauds the Administration's position, and we hope that it will be implemented vigorously. We believe it makes as much good sense to consider energy policy implications during environmental rulemaking as it does to incorporate environmental considerations during the execution of energy policy initiatives.

Important environmental considerations are now ingrained in practically every facet of policy implementation, and indeed every business decision. So too should energy policy considerations. Does consideration of environmental impacts slow down, or "hinder" policy and business activity? Most certainly, and occasionally to an excruciating degree. But society has deemed environmental consequences to be so important that such delays may be necessary. The EPA's charge is to ensure that no policy or project that could impact on the environment moves forward until or unless environmental considerations are adequately addressed.

Similarly, an effectively implemented energy policy is vital to our future national and economic security. It makes eminent sense to require the consideration of impacts on energy policy objectives in any rulemaking that might have such impacts. Based on our experience, that is most certainly the case for most environmental regulations.

Neither policy arena should be permitted to operate in isolation and turn a blind eye to the other. The National Council believes that society can be better served if both environmental and energy policy objectives are pursued in a balanced fashion.

CONCLUSION

The National Council is deeply appreciative of the heavy burdens carried by those charged with finding ways to (1) enhance domestic energy production and more efficient consumption, and (2) pay for our nation's energy and defense "insurance policies." All are basic to our existing and future national and economic security.

The authors of S. 341 can justifiably point with pride to the overall balance of this legislation. However, the National Council believes the Oil Security Premium in Title VII detracts from that desirable balance, and is not an appropriate part of the solution. We would respectfully urge that the Oil Security Premium be dropped from S. 341. We would also encourage amendment of S. 341 to improve SPR drawdown policy by at a minimum limiting the universe of eligible bidders to operating domestic refiners and marketers.

In closing, the National Council shares the stated commitment of the Committee leadership to develop a responsible and balanced National Energy Strategy, and we stand ready to work with the Committee and the Congress toward enactment of such a bill.

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STATEMENT FOR THE RECORD
BY
UNITED STATES SENATOR BOB GRAHAM
ON
TITLE VIII, OUTER CONTINENTAL SHELF
OF
S. 341, THE "NATIONAL ENERGY SECURITY ACT OF 1991"

Mr. Chairman:

Thank you for providing me this opportunity to present my views on the proper role of offshore oil and gas in meeting the nation's energy needs.

While it is clear to me that the nation must develop and aggressively pursue a forward-looking energy policy, it is not clear what role offshore oil and gas ought to play in that policy.

As a member of Florida's congressional delegation I have witnessed a steady growth in my constituents' concern that offshore drilling could lead to an oil spill that would devastate the state's fragile and extremely important coastal environment, possibly destroying resources of national significance including the Florida Keys, the Everglades, and habitat critical to the survival of many species of fish and wildlife.

I believe the citizens of coastal states should have real authority to meet their concerns related to offshore drilling. It should be up to the citizens of Florida, acting through the Chiles administration, to determine if, and under what circumstances, the risks to their unique environment of oil and gas operations are worth taking.

Unfortunately, under the Outer Continental Shelf (OCS) Lands Act, the authority of coastal states to protect their coastal environment and resources is very limited.

Under the OCS Lands Act, the Secretary of Interior is to consult with the governor of the adjacent state in developing a five-year lease plan, and in developing plans for a specific lease sale. Frequently, however, this consultation obligation appears to have been taken lightly, and governors' comments have been essentially ignored.

If consultation does not produce a satisfactory result and a state still wants to pursue an objection to a lease sale or five-year plan, it has little choice but to initiate complex and costly litigation. When that course is taken, the state must demonstrate that the Secretary's action was "arbitrary and capricious," a very difficult legal standard to meet.

An energy resource program that produces lawsuits instead of energy needs to be reformed.

It would make far more sense for all concerned -- coastal states, the federal government and the industry -- to determine before a lease is ever offered for sale exactly what conditions need to be addressed to assure the adjacent state that its interests will be protected. Resolving environmental and other concerns before leases are sold would reduce litigation, increase the probability that a lease purchaser will be allowed to develop that lease, and eliminate the potential for bias created by tens of millions of dollars being paid into the Treasury before environmental studies are completed.

I have introduced legislation (S. 736) to eliminate these deficiencies in the OCS program. The bill will:

- establish as national policy to guide the OCS program that protection of the environment is as important as producing oil and gas;
- reverse the burden of proof in the Secretarial consultation process so that a governor's recommendations are binding unless the Secretary demonstrates that the governor's actions are arbitrary and capricious, or based on a material error of fact; and
- require that all environmental studies pertinent to a particular lease sale be completed, peer reviewed and made available for public review at least six months before that lease sale is announced.

Governor Chiles has asked President Bush and Secretary Lujan to establish a 100-mile buffer zone around Florida's coast within which no oil and gas activities would be permitted. I endorse Governor Chiles' request, and have introduced legislation (S. 734) to establish that buffer zone. The bill also would:

- permanently prohibit oil and gas operations off Southwest Florida adjacent to the Everglades and the Keys;
- require that existing leases in the areas subject to permanent prohibitions be cancelled and bought back by the federal government; and

o impose a moratorium until the year 2002 on offshore activity other than environmental studies in the rest of the Eastern Gulf of Mexico Planning Area lying east of the Alabama-Florida boundary.

Establishing a buffer zone around Florida clearly makes sense when viewed from a cost-benefit perspective.

On the benefit side of the equation, the Minerals Management Service estimates the probable oil reserves in the Sale 137 area (the Eastern Gulf off Florida, north of 26 degrees north latitude) at 50 million barrels of "oil equivalent" (draft Environmental Impact Statement for Sale 137, at page I-5). That amount, at the January 1990 rate of U.S. consumption, would last roughly three days.

The costs, however, could be staggering.

An article in Science (Vol. 243, January 6, 1989) discusses research conducted in Panama on the effects of oil spills in a tropical environment. I request that the article appear in the record following this statement.

The article focuses on a 1986 spill that affected a coastal environment remarkably similar to the Gulf coast of Florida. Considerable study of the spill site had been conducted before the spill, enabling scientists to make clear before-and-after comparisons to document the spill's effects.

The effects included destruction of "intertidal mangroves, seagrasses, algae, and associated invertebrates" and "extensive mortality of shallow subtidal reef corals and infauna of seagrass beds." One-and-one-half years after the spill, "only some organisms in areas exposed to the open sea (had) recovered."

The risk of destruction of this magnitude far outweighs any benefit from producing a mere three days' supply of petroleum.

Clearly, the federal government needs to put its energy house in order. We have not had a national energy policy for over a decade. We continue to address our energy needs in terms of surviving the current crisis, when we ought to be planning ahead and establishing policies that will reduce the potential for crises to occur.

The Administration's recent National Energy Strategy and the Interior Department's draft Proposed 5-Year Offshore Gas and Oil Program offer no improvements. They emphasize increased reliance on domestic oil and gas to meet a major part of our energy needs, and adopt the view that all we need to do to avoid excessive dependence on petroleum imports is drill our domestic reserves as fast as we can.

Regrettably, in many respects S. 341 adopts the same basic approach. Its OCS provisions focus on eliminating restrictions on offshore drilling, and on giving monetary incentives to coastal states to encourage them to allow drilling to proceed.

The "drain America first" approach is wrong for a number of reasons:

- First, it fails to recognize that dependence on petroleum -- and not on imports per se -- has created our vulnerability;

- Second, it reflects little concern for the potential effects of offshore oil and gas operations on the coastal and marine environment;

- Third, it shows no serious interest in developing alternative energy resources and technologies and improving efficiency; and

- Fourth, it is a short-term, stop-gap approach rather than a genuine long-term answer to the problem of providing adequate energy to sustain our economy and our quality of life.

Mr. Chairman, thank you for including my views in the record of your committee's hearings on S. 341.

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SCIENCE

Ecological Effects of a Major Oil Spill on Panamanian Coastal Marine Communities

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In 1986 more than 8 million liters of crude oil spilled into a complex region of mangroves, seagrasses, and coral reefs just east of the Caribbean entrance to the Panama Canal. This was the largest recorded spill into coastal habitats in the tropical Americas. Many populations of plants and animals in both oiled and unoiled sites had been studied previously, thereby providing an unprecedented measure of ecological variation before the spill. Documentation of the spread of oil and its biological effects begun immediately. Intertidal mangroves, seagrasses, algae, and associated invertebrates were covered by oil and died soon after. More surprisingly, there was also extensive mortality of shallow subtidal reef corals and infauna of seagrass beds. After 1.5 years only some organisms in areas exposed to the open sea have recovered.

OIL POLLUTION IN THE SEA HAS BEEN A MAJOR ENVIRONmental problem for several decades, but we know remarkably little about the effects of oil on natural populations and communities (*1*). Uptake of oil and physiological responses of organisms have been investigated in the laboratory or field, sometimes coupled with short-term monitoring of communities and of amounts of oil in water, sediments, and organisms (*2*, *3*). Investigations of oil spills generally commence after any initial damage has occurred, and baseline ecological data are usually lacking. This approach precludes measurement of the effect of oil spills because there usually is no knowledge of natural ecological variation (*2*). Such was the case in 1968 following the release of 3.2 million liters of oil from the wreck of the *Witwater* near the Galeta Marine Laboratory (Smithsonian Tropical Research Institute) in Panama (*4*, *5*). Another even larger spill occurred in the same region in 1986 (*6*) (Fig. 1). In this article, we describe the types and extent of damage to coastal populations and communities in the first 1.5 years after the 1986 spill, and contrast our findings with earlier work and widely held views regarding the effects of oil on tropical coastal communities.

Our study is unique for two reasons. First, many of the habitats damaged by oil have been investigated since the *Witwater* spill 18 years before. Results of this research have been published in more than 130 articles, and the flora and fauna are well known taxonomically (*7*). Detailed time-series data on the physical environment and biota (*8*, *9*) provide a measure of natural variation before the more recent oil spill against which subsequent events can be compared. Second, observations of the effects of the spill began as oil was coming ashore. Of additional importance, the coastal environments (including seagrass beds, mangroves, algal flats, and coral reefs) and most of the species affected are similar to those throughout the

Fig. 1. Crude oil washing onto Galeta Reef on the Caribbean coast of Panama, site of a 15-year-old environmental monitoring program at the Galeta Marine Laboratory, Smithsonian Tropical Research Institute (white building on reef platform). [Photo by C. Hansen]

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Caribbean, Gulf of Mexico, and southeastern United States (*10*). Thus our observations are relevant to assessment of potential biological effects of pollution in several areas where extraction or refining of oil is ongoing on planned (*11*).

On 27 April 1986 at least 8 million liters of medium-weight crude oil (*12*) spilled from a ruptured storage tank into the sea on the Caribbean coast of Panama (*6*) (Fig. 2). This is the greatest amount of oil spilled directly into a sheltered coastal habitat in the tropical Americas (*3*, *13*). For 6 days, onshore winds held the oil within Bahia Cativa adjacent to the refinery (Fig. 2), but runoff from rains and shifting winds then flushed the oil out to sea. At this time dispersant was sprayed on slicks in the mouth of Bahia las Minas and offshore (*14*). By 15 May, the oil had swept across fringing reefs and entered mangrove forests, small estuaries, and sand beaches within 10 km of the refinery.

Table 1. Comparison of visual assessment of amount of oiling on four coral reefs [ranked heavy (H), moderate (M), and none (N)] with results of gas chromatographic (GC) analyses of saturated hydrocarbons in coral tissues and by ultraviolet fluorescence (UVF) analyses of aromatic hydrocarbon fractions. Oil content by GC was conservatively estimated as the unresolved hydrocarbons in the elution range for alkanes containing 12 to 36 carbon atoms. Oil units by UVF were determined by comparison with the spilled oil. Values are expressed as micrograms per milligram of coral tissue (lipid or protein) and are the mean and standard deviation of triplicate analyses. Reefs are listed from west to east (Fig. 2); Payardi West is adjacent to the refinery and Palina West is just west of Isla Grande.

Reef	Oiling	Petroleum hydrocarbons in coral tissue (μg) per milligram of		
		Protein by GC	Lipid by GC	Lipid by UVF
Galeta Channel	H	0.71 ± 0.11	2.7 ± 1.1	5.0 ± 3.4
Payardi West	H	0.78 ± 0.17	4.5 ± 0.8	25.5 ± 6.0
Naranjos South	M	0.32 ± 0.05	1.4 ± 0.1	1.3 ± 0.3
Palina West	N	0.22 ± 0.15	1.0 ± 0.6	0.1 ± 0.1

Plants and animals died wherever they came in contact with oil. However, the types and magnitude of effects varied greatly with coastal topography and location, and among habitats and taxa. Such complex effects are similar to those of powerful hurricanes on Jamaican and Australian coral reefs (*15*). We first consider the spatial pattern of the spill and its effects in different environments, including variations in effects on different taxa. We then describe the patterns of responses of different organisms that discuss prospects for recovery.

Spatial Distribution of Oil Among Habitats

The distribution of oil within 2 months of the spill was visually assessed by aerial surveys between Rio Chagres, 27 km west of the refinery, and Punta San Blas, 98 km to the east, and by boat and foot from Rio Chagres to Nombre de Dios (*16*) (Fig. 2). No oil was observed on shorelines east of Isla Grande, and only a few patches were observed east of Maria Chiquita and west of the Panama Canal entrance. Heavy oiling occurred along most of the coast between Isla Margarita and Islas Naranjos (Fig. 2). The straight-line distance between these two points is 11 km, but the labyrinthine shoreline is at least 82 km long and contains about 16 km^2 of mangroves and 8 km^2 of intertidal reef flats and subtidal reefs (*17*). Within this area, the only large unoiled areas 2 months after the spill were two mangrove lagoons that are isolated from open water by narrow channels (hatched areas in Fig. 2). Oil slicks ranging from a metallic sheen to brown patches are still common between Punta Muerto and Galeta, especially after heavy rains flush oil from mangroves and from the landfill beneath the refinery (*18*).

Within similar habitats, distance from the refinery, direction of oil movement, and water depth apparently caused considerable variation in the degree of oiling even in the most polluted region. Amounts of oil observed on or in sediments of seagrass beds, mangroves, and over reef flats were highest within a few kilometers of the refinery (Punta Muerto to Largo Remo and Punta Galeta)

Table 2. Population changes of gonodactylid stomatopods on four reef flats. Data for all years are from August to September. Densities and growth are given as the means ± SE.

Measure	Year	Location			
		Isla Margarita	Largo Remo West	Mina	Largo Remo North
Oiling		Light*	Light*	Heavy†	Heavy‡
Density/m^2	1986	9.9 ± 1.5§	6.1 ± 1.5	4.9 ± 0.9	1.8 ± 0.4
Individuals ≥40 mm (%)	1986	9	20	3	4
Injured animals ≥35 mm (%)	1980	25			
	1981	31	36	35	20
	1982		21‖		
	1983			23	
	1986	38	38	11¶	10**
Growth†† (%)	1979–1983	6.3 ± 1.2		6.1 ± 1.1	
	1986	6.3 ± 1.2		9.4 ± 1.2	

*No oil evident on surface or in sediments and *Thalassia* appeared healthy. †Abundant oil on and in sediments and on adjacent mangroves. *Thalassia* leaves shed, but rhizomes appeared to be alive. ‡Entire *Thalassia* bed is gone, no leaves are present and the rhizomes are dead. §Mean density here prior to the spill was 9.6 ± 0.59; no comparable data on densities are available for the other sites. ‖Significantly different from 1981 to 1986, *G* test, $P < 0.01$. ¶Significantly different from previous years. *G* test, $P < 0.01$. **Significantly different from 1980, *G* test, $P < 0.05$. ††Values pooled for the two heavily oiled and lightly oiled sites. Analysis of covariance showed that slopes of percent growth against body length were not significantly different among the four groups of data ($P > 0.05$), but that mean growth adjusted for elevation did differ significantly ($P < 0.001$). There was a significant increase in adjusted mean growth at the heavily oiled sites after the spill compared to growth at these sites before the spill; there were no significant differences in adjusted mean growth at the lightly oiled sites before and after the spill, and between the lightly and heavily oiled sites prior to the spill.

and much less at Islas Naranjos and Isla Margarita (*19*). Moreover, similar differences occurred over just a few hundred meters between shores directly exposed to or sheltered from the wind-driven oil (*20*). On an even smaller scale, extreme low tides between 10 and 19 May (*6*, *21*) caused oil to accumulate along the seaward borders of reef flats, whereas just shoreward much less oil contacted the substratum. In general, intertidal habitats just above mean low water were the most heavily oiled, including mangrove roots and sedi-

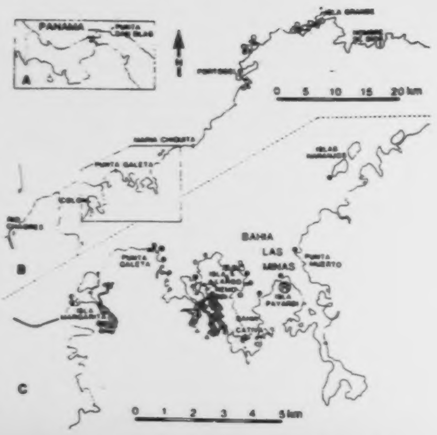


Fig. 2. Region of the Republic of Panama affected by the 27 April 1986 oil spill, shown as increasing enlargements (A to C). (**A**) Location within Panama, just east of the Caribbean entrance to the Panama Canal. (**B**) The boxed area includes the most heavily oiled coastal habitats. Punta Galeta, inside the boxed area, is 9°24′N, 79°52′W. Lightly oiled and unoiled study sites are east of Bahia las Minas, near Portobelo and Isla Grande. (**C**) Detail of the most heavily oiled area and location of study sites. Encircled "R" on Isla Payardi marks the refinery where the oil spill occurred. Horizontal hatching denotes embayments where little oil penetrated. Symbols for types of study sites (open symbols, unoiled or lightly oiled sites; filled symbols, oiled sites): △, mangrove root; □, seagrass bed; ○, subtidal coral reef, data collected only after the oil spill; ◐, subtidal coral reef, data collected both before and after the oil spill: the four sites near Portobelo and Isla Grande were not oiled, the site at Isla Margarita was moderately oiled, and the site at Punta Galeta was heavily oiled; ◇, reef-flat stomatopods; multirayed star, reef flat community, Punta Galeta; six-rayed symbol, mangrove forest.

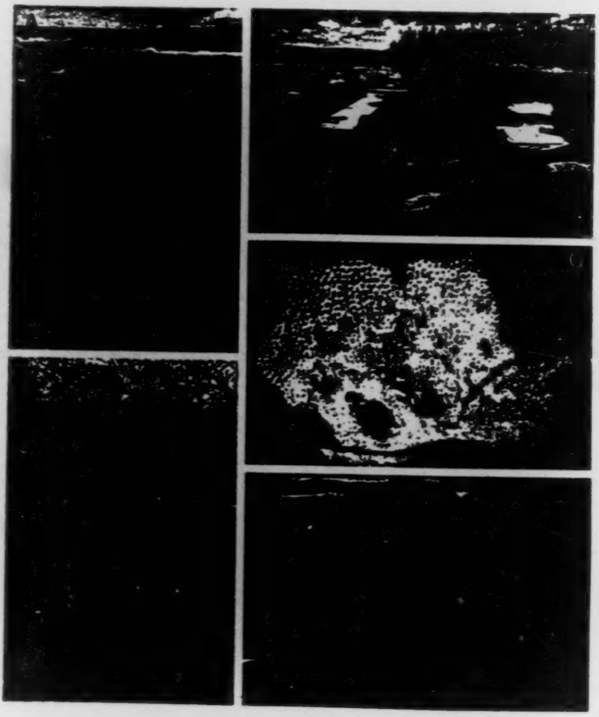


Fig. 3. Organisms and habitats affected by the April 1986 oil spill at Bahia las Minas, Panama [all photographs by C. Hansen except (D) by S. D. Garrity]. (**A**) Oil accumulated along the seaward edge of the Galeta reef flat at low tide (seen as the dark border in the cover photo), directly coating and killing plants and animals, including the zoanthid *Palythoa* sp. (lighter patches in foreground) and the hydrocoral *Millepora* sp. (projecting through oil in background). (**B**) At high tide oil accumulated along sand beaches, where it soaked into the sand and settled onto the shoreward reef flat at low tide, killing seagrasses, algae, and invertebrates. The rectangular objects in the foreground are polyurethane mattresses used by cleanup crews to absorb oil. (**C**) Underwater view of the coral *S. siderea* partially killed by oil (horizontal length in the photograph, 12 cm). Live tissue forms the dark reddish area at the bottom. The central, light-colored area is skeleton showing through partially dead tissue, which is also being colonized by algae. The lightest area at the top is bare skeleton covered by a film of microalgae. (**D**) Oil-covered intertidal surfaces of prop roots of the red mangrove, *R. mangle*, killing oysters and other epibiota on the roots. Relieved of the weight of their leaves, defoliated branches flexed upward, lifting the roots out of the water and thus killing subtidal epibiota that previously escaped direct contact with floating oil. (**E**) Dead mangrove trees form a band about 8 to 100 m wide (February 1987), marking the area where oil accumulated as it entered the mangrove forests (horizontal distances: foreground ~0.4 km and background ~1.3 km). A band of defoliated trees was apparent within 2 months after the spill and widened thereafter.

ments, reef-flat seagrass beds, coral rock, and beaches. In contrast, higher than normal seas after the *Witwater* spill caused heaviest oiling in high intertidal and supertidal habitats, with much more transport of oil into mangroves far from shore (*4*). Much less oil was observed subtidally.

In addition to these qualitative observations, samples of water, substrata, and organisms were collected for analysis of hydrocarbons by means of gas chromatography and ultraviolet fluorescence analysis of aromatic hydrocarbon fractions (*22*). Preliminary results generally parallel classification of sites based on visual inspection, as shown here for the concentration of saturated hydrocarbons in tissues of the coral *Siderastrea siderea* (Table 1).

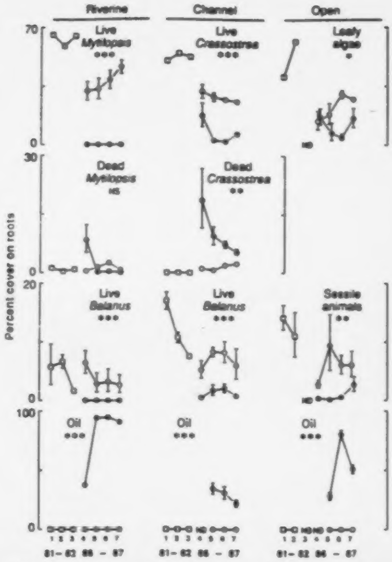


Fig. 4. Percent cover of formerly abundant taxa and oil on mangrove roots in riverine, channel, and open coast habitats before and after the oil spill. □, Prespill data; ○, unoiled sites; and ●, oiled sites. Means are plotted ±1 SE, converted from arcsine transformations. Some error bars lie within the plotting symbols, except for sampling time 3, when $n = 1$. ND, no data. "Leafy algae" include *Polysiphonia*, *Acanthophora*, and *Ceramium* as common genera; the most abundant "sessile animals" include hydroids and sponges. Sampling dates: 1 = September to October 1981; 2 = January 1982; 3 = June 1982; 4 = July to August 1986; 5 = October to November 1986; 6 = February 1987; and 7 = May 1987. Results of repeated measures analysis of variance for oiled and unoiled sites after the spill are shown on each graph. NS, $P > 0.05$; *, $P < 0.05$; **, $P < 0.01$; ***, $P < 0.001$.

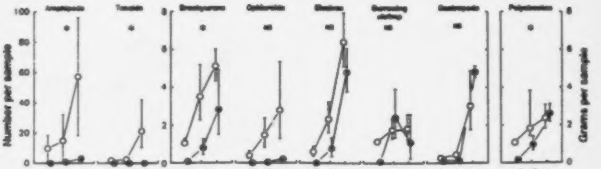
Biological Effects

Consequences of the spill were assessed differently, depending on the types of data available from before the oil spill (*23*). Ideally, biological parameters should have been measured at oiled and unoiled sites before and after the spill. This condition was satisfied for biota of mangrove roots and subtidal corals. Extensive prespill data are available for the reef flat at Galeta, but there are no control sites and effects must be inferred from temporal change and from the spatial distribution of oiling on the reef flat. In contrast, there are little or no appropriate prespill data for subtidal seagrass communities. In this case, comparisons were made between oiled and unoiled sites after the spill, confounding the treatment (oiling) and geography (Bahia las Minas verus the region between Portobelo and Isla Grande) (Fig. 2). The value of this approach is strengthened by information suggesting that faunas in seagrass beds were similar in the two regions before the spill (*24*), but confidence in assessment of oiling effects in this habitat is still more limited than in other habitats studied.

Mangrove communities. Red mangrove, *Rhizophora mangle*, forms nearly all of the fringing forest along this coast (*17*). By September 1986, a band of dead or dying trees marked the zone where oil washed ashore between Punta Galeta and Islas Naranjos (Fig. 3); no such band appears in photographs taken just as the oil was coming ashore. By November 1987 dead mangroves occurred along an estimated 27 km of the coast (*25*). Seedlings transplanted to heavily oiled sites did not produce new leaves, in contrast to transplants at an unoiled site (*26*).

The prop roots of *R. mangle* are overgrown by algae and invertebrates that vary in species composition with exposure to the sea (Fig. 3) (*6, 27*). The epibiota on roots in three different habitats were sampled before and after the spill (Fig. 2) (*28*). Before the spill (Fig. 4), roots of trees directly facing the open ocean were covered with foliose algae and sessile invertebrates such as sponges, hydroids, and ascidians. In mangrove channels, the edible oyster, *Crassostrea rhizophorae*, and a barnacle, *Balanus improvisus*, were most abundant on roots. Roots in small rivers were dominated by the false mussel *Mytilopsis domingensis* and *B. improvisus*. Certain groups were more abundant a few years before the oil spill (1981 to 1982) than in 1986 to 1987 at unoiled sites (Fig. 4), possibly because of natural fluctuations in abundance. After the spill, the cover of all major groups was very greatly reduced in each oiled habitat (Fig. 4). There has been patchy recovery in the open habitat of foliose algae and sessile invertebrates, although not of the same relative abundance of species. In the channels, cover of both the oyster and

Fig. 5. Abundance or biomass per sample of eight major infaunal taxa in three oiled (●) and four control (○) seagrass beds 5, 7, and 9 months after the oil spill (*30*). Means are plotted ±1 SE, backtransformed from ln $(x + 1)$; some error bars lie within the plotting symbols. "Burrowing shrimp" include alpheids (most abundant), processids, callianassids, and upogebids. NS, $P > 0.05$; *, $P < 0.05$ by repeated measures analysis of variance. Number per sample is shown at two scales. Data for polychaetes are shown as grams per sample.



barnacle dropped greatly and have since recovered little. False mussels and barnacles disappeared in oiled rivers and were not recorded again until 15 months after the spill.

The greatest cover on roots in all oiled habitats after the spill was oil (Fig. 4). In addition, most roots sampled for epibiota (*28*) were dead, broken, or rotting by August 1987 (54% on open coasts, 56% in channels, and 66% in rivers at oiled sites versus 8%, 1%, and 3%, respectively, at unoiled sites). Thus the mangrove-fringe root habitat has been largely destroyed at oiled sites and will not be restored unless new trees grow.

Seagrasses. Extensive meadows of the seagrass *Thalassia testudinum* cover much of the intertidal reef platforms and subtidal floors of shallow embayments and lagoons along this coast (*24*). Entire beds of intertidal *Thalassia* were killed on some heavily oiled reef flats, as shown by abundant oil-covered dead leaves washed ashore and dead but intact root-rhizome mats (for example, the site at Largo Remo North) (Table 2). In contrast, subtidal *Thalassia* survived everywhere after the spill, although leaves became brown and heavily fouled by algae for several months in heavily oiled areas.

Thalassia provides food, habitat, and refuge for dense populations of invertebrates and fishes (*24, 29*). Before the spill, amphipods, small decapods, ophiuroids and other echinoderms, bivalves, gastropods, polychaetes, and small fishes were all abundant in seagrass within the study area (*24*) and still are in unoiled beds (Fig. 5). Sampling of infauna began September 1986 at three oiled and four unoiled sites (*30*) (Fig. 2). Four taxa of invertebrates were significantly less abundant in oiled grassbeds after the spill, but four others showed no such difference (Fig. 5). Abundances of most taxa increased between September and January; preliminary analyses of body size indicate that recruitment caused these increases. Only the abundance of hermit crabs increased in oiled relative to unoiled areas (7.3 versus 3.4 crabs per sample, respectively, in January 1987, $P < 0.05$, repeated measures analysis of variance), perhaps because of a surplus of shells of recently dead snails (*31*).

Intertidal reef flats. Platforms of fringing reefs from extensive shallow to intertidal flats throughout the study region (Fig. 3) (*7, 9, 17, 32*). Populations on the reef flat at Punta Galeta have been monitored for up to 15 years (*9*) (Fig. 2). Damage was most extensive at the seaward border, where the oil accumulated at low tide. Immediately after the spill a bloom of microalgae covered recently vacated substratum (*33*) (Fig. 6). This area had been dominated by perennial macroalgae, particularly the fleshy red alga *Laurencia papillosa*, crustose corallines, and the articulated calcareous green alga *Halimeda opuntia*. Cover of all these plants was reduced to levels well below those observed previously, but had regained or exceeded typical abundance within 12 to 18 months, concurrent with a reduction of the microalgae. The most common sessile animals before the spill were zoanthids (*Zoanthus sociatus* and *Palythoa* spp.), hydrocorals (*Millepora* spp.), and scleractinian corals (*Porites* spp.). At the seaward border of the reef flat, populations of all these animals were severely reduced, and only *Zoanthus* had returned to typical abundance after 18 months (Fig. 6). Densities of sea urchins on the reef flat varied over three orders of magnitude before the spill (Fig. 6) (*9*). At the seaward edge, the most abundant

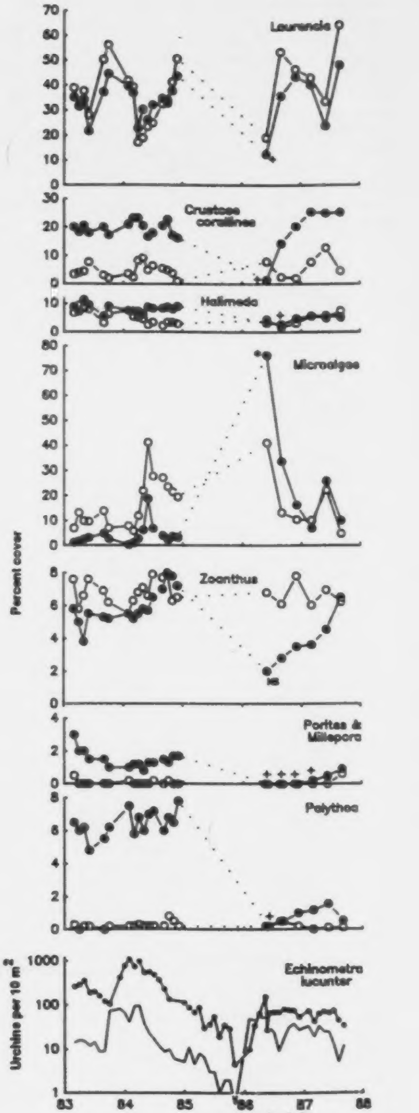


Fig. 6. Pre- and postspill comparisons of the abundance of algae and sessile animals (top seven panels) and the sea urchin *Echinometra lucunter* (bottom panel) on the seaward portion of the Galeta reef flat (*33*). Filled symbols denotes the heavily oiled zone closest to the water's edge at low tide (Fig. 3). Open symbols and the smooth line in the *E. lucunter* graph indicate less oiled (more landward) habitats; * and + mark postspill surveys of percent cover that were significantly higher or lower than any prespill survey at $P \leq 0.05$ and $P \leq 0.01$, respectively. In all cases, differences were significant only in the heavily oiled zone (●). Cover was compared survey by survey with the use of paired *t* tests matched by individual transects within surveys. Abundances of *E. lucunter* were compared with the use of residuals from regressions (*34*).

urchin *Echinometra lucunter* was reduced by about 80% within a few days of oiling, and the reef flat was littered with its skeletons. Although this decrease was small in an absolute sense relative to changes in abundance among years, it nevertheless departed significantly from the average trend in abundance between months of May and June over the last 8 years (*34*). Farther inshore, no such reductions occurred.

Gonodactylid stomatopods (mantis shrimp) are abundant in intertidal *Thalassia* beds from Isla Margarita to Isla Largo Remo, where they live in and aggressively defend cavities in coral rubble at densities up to 20 per square meter (*35*). They are prey for shorebirds, fish, and crabs, and in turn consume large numbers of hermit crabs, snails, and other animals (*36*). Population data are available for stomatopods from intertidal seagrass beds on four reef flats, including certain types of data collected at various times before the spill (Table 2 and Fig. 2). Two of the sites were heavily oiled, and large amounts of oil were still present on mangrove roots and in sandy sediment when sampling first began 3 months after the spill; the other two flats were at most lightly oiled. Densities of stomatopods were less on the heavily oiled flats, particularly for animals greater than 40 mm long (*37*). Loss of these large animals apparently made larger cavities available to the survivors, which consequently fought less and suffered fewer injuries (*38*) compared to the same sites before the spill and compared to lightly oiled flats afterwards (Table 2). Growth of larger survivors also increased on heavily oiled flats (*39*), probably because of decreased competition for cavities and an apparent population explosion of hermit crabs for food (*35*, *40*). These effects have persisted in diminished form through our last census in September 1987.

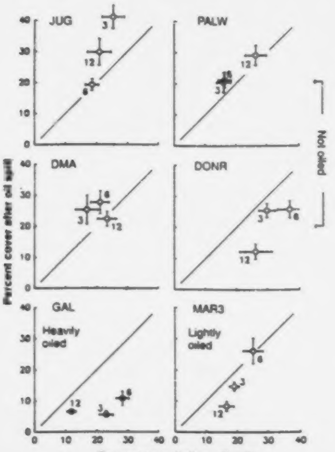


Fig. 7. Percent cover of corals before the oil spill plotted against their cover afterward. The diagonal lines represents no change in coral cover; points below this line indicate a decrease after the spill, and points above the line show an increase. The points are means ± 1 SE; some error bars lie within the plotting symbol. Oiling significantly affected coral cover only at the shallowest depth (*42*). Abbreviations: 3, 0- to 3-m depth; 6, 3- to 6-m depth; and 12, 6- to 12-m depth. JUG and PALW are located just west of Isla Grande. DMA and DONR are northeast of Portobelo. GAL is at Punta Galeta, and MAR3 is at Isla Margarita (Fig. 2, half-filled circles).

Subtidal reefs. Populations of subtidal sessile organisms were surveyed on six fringing reefs between Isla Margarita and Isla Grande within 1 year before and 4 months after the oil spill (Fig. 2) (*41*). These include the heavily oiled reef at Punta Galeta, a lightly oiled reef at Isla Margarita, and four unoiled reefs east of Portobelo. Abundance of most common scleractinian coral genera in depths ≤3 m decreased at Galeta by 51 to 96%, and total coral cover decreased by 76%; even at 9 to 12 m the drop was 45% (Fig. 7). Reductions were less at Isla Margarita and generally absent on the unoiled reefs, except at one site northeast of Portobelo (Fig. 2) for no apparent reason. This relation between amount of oiling on the six reefs and decrease in coral cover was significant for 0 to 3 m but not deeper (*42*).

Sublethal effects were also substantial. Within Bahia las Minas, most of the scleractinians still alive in depths less than 3 m showed signs of recent stress including bleaching or swelling of tissues, conspicuous production of mucus, recently dead areas devoid of coral tissue, and globules of oil (Fig. 3) (*43*). In some cases, bleached or dead areas were surrounded by a black halo characteristic of bacterial infection (*44*). Both the frequency and size of recently dead lesions on the commonest massive corals increased markedly with the amount of oiling at each reef and decreased with water depth (Fig. 8) (*45*, *46*). These effects were also species specific. In the case of *S. siderea*, which suffered most, new partial mortality was still disproportionately common on heavily oiled reefs 1 year after the spill (*46*).

The oil spill also affected other organisms, including snails on the reef flat and intertidal zone at Punta Galeta and mobile epifauna, particularly shrimps above subtidal seagrasses. In summary, the spill harmed prominent organisms in all intertidal and subtidal environments examined, infauna and epifauna, and members of all trophic levels including primary producers, herbivores, carnivores, and detritivores.

Patterns of Responses and Their Significance

The severe damage to intertidal biotas and their response, such as the flush of ephemeral microalgae just after the spill, are similar to those documented previously for other oiled intertidal communities (*47–50*), including those inferred for Galeta after the *Witwater* spill (*4*). Likewise, biological effects of spills are usually greatest in low energy environments, where oil tends to accumulate and be retained in fine sediments, than in high energy environments where it is soon washed away (*50*). This pattern matches the greater and more persistent disturbance to riverine and channel mangrove root communities than to those along open coasts and the rapid recovery in abundance of many organisms at the seaward edge of the reef flat (Fig. 6).

In contrast, other results were not expected, and in some cases contradict widely held views about the effects of oil spills and the ways they are studied. First, extensive mortality of subtidal corals and infauna of seagrasses had not been demonstrated before (*1*, *3*) and contradicts undocumented assertions that these organisms are not affected by oil spills. In part, subtidal effects may have been caused by the use of dispersant (*51*) but it seems unlikely that this was the only reason, given the regional breadth of the impact and the relatively small amount of dispersant employed (*14*).

Second, the magnitude of subtidal coral mortality and injury within Bahia las Minas is in striking contrast to findings of no lasting change in coral condition or growth after exposure to oil, with or without chemical dispersant, in small-scale experiments (*51*, *52*). Such discrepancies underlie the importance of detailed long-term ecological studies, and the dangers inherent in extrapolation to

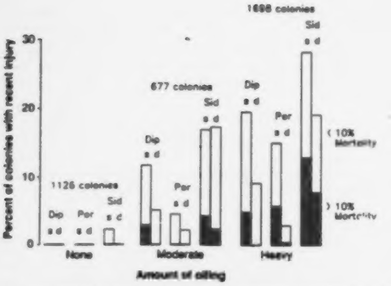


Fig. 8. Frequency of injury for the three most common species of massive corals in relation to the amount of oiling at 12 reefs (4 unoiled, 3 lightly to moderately oiled, and 5 heavily oiled). Open bars represent coral colonies with injuries that did not exceed 10% of the surface area of the coral; filled bars represent injuries greater than 10% (maximum observed, 100%). Sample sizes are shown above each category of oiling. Abbreviations; Dip, *Diploria clivosa*; Por, *Porites astreoides*; Sid, *Siderastrea siderea*; s, shallow (0 to 1 m); and d, deep (1 to 2 m).

natural populations from laboratory-based physiological data or small-scale, short-term press perturbation experiments in the field (*2, 3, 48, 52, 53*).

Third, sublethal effects are extensive and may be more important in the long term than initial mortality (*3, 48*). Changes in stomatopod behavior and population structure were more pronounced than might be expected from a simple reduction in numbers. Likewise, injury of corals has allowed colonization of their bare skeleton by algae and other sessile organisms that may overgrow parts of colonies that survived the initial effects of oil (*3, 54*). Corals stressed by oil are probably also more susceptible to epidemic disease and likely to grow and reproduce more slowly than unaffected colonies (*3, 5, 52*). Any combination of these effects may further reduce overall abundance of corals as much as the initial spill (*54*). Such a chain reaction could continue long after any petroleum hydrocarbons are present in the environment or coral tissues, just as staghorn coral continued to decline precipitously following a severe hurricane in Jamaica (*55*).

The response of organisms to an oil spill, or any other major disturbance, will depend on the conditions in which they normally live (*15, 48, 56*). Moreover, the suite of organisms able to survive under conditions of chronic pollution, and their resistance to further stress, is typically different from that in similar unpolluted habitats (*48, 57*). Much of Bahia las Minas has been subjected to human disturbance, beginning with decades of excavation, dredging, and landfilling for the construction of the Panama Canal and the City of Colon, drainage and spraying of mangroves for mosquito control, construction of the refinery and a large cement plant on landfill, a major oil spill in 1968, and unknown amounts of chronic oil pollution from the refinery and ships passing to and from the Canal (*4, 5, 17, 58*). It is a measure of the severity of the 1986 oil spill that the biological consequences were so detectable despite this history of environmental abuse.

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10. J. C. Ogden and E. H. Gladfelter, *UNESCO Tech. Pap. Mar. Sci.* 23, 1 (1983). Important species in common throughout the tropical western Atlantic are red mangrove *R. mangle*, seagrass *T. testudinum*, most reef corals and algae, and commercially important lobsters (*Panulirus* spp.) and oysters (*C. rhizophorae*).
11. Ongoing drilling and refining off Yucatan and possible production along the west coast of Florida.
12. The oil type was 70% Venezuelan crude, 30% Mexican Isthmus crude, specific gravity 27° (American Petroleum Institute). Percent composition determined at the Bermuda Biological Station by column chromatography with the use of alumina and silica gels: 47.4% saturates (fraction 1, hexane); 6.4% light aromatics (fraction 2, 10% ether/90% hexane); 4.8% heavy aromatics (fraction 3, 20% methylene chloride/80% hexane); 18.9% polar fraction (fraction 4, methylene chloride); and 22.5% unrecovered.
13. C. D. Getter, G. I. Scott, J. Michel, in *1981 Oil Spill Conference* (Publ. 75-4161, American Petroleum Institute, Washington, DC, 1981), pp. 535–540.
14. Refinery officials estimated that <21,000 liters of Corexit 9527 (Exxon Chemicals America) were sprayed from aircraft (*6*). STRI personnel observed this spraying between Maria Chiquita and Punta Galeta.
15. J. D. Woodley *et al.*, *Science* 214, 749 (1981); J. H. Connell, *ibid.* 199, 1302 (1978).
16. Surveys beyond Punta Galeta began the first week of June 1986 and lasted 1 month. Videotapes were made of the coast between Rio Chagres and Islas Naranjos, and still photographs were made all along the coast. Visual assessments were made of degree of oiling (heavy, moderate, light, or absent) and the habitats and types of organisms obviously affected.
17. J. D. Cubit, G. Batista de Yee, A. Roman, V. Batista, in *Agonia de la Naturaleza*, S. Heckadon Moreno and J. Espinosa Gonzalez, Eds. (Impretex, Panama, 1985), pp. 183–199; *Revista Medica Panama* 9, 56 (1984).
18. Oil was observed commonly until the time of manuscript revision (July 1988) around Isla Pavardi, where it emerged directly from the coral landfill on which the refinery is built, and Punta Muerto, Bahia Cativa, eastern Isla Largo Remo, and Punta Galeta.
19. Within this area oil commonly escaped from sediments when we walked among mangroves or cored into shallow subtidal seagrass beds. Intertidal surfaces were heavily coated with oil.
20. Most of the oil that escaped from Bahia Cativa was driven west. Coasts facing north to northeast were heavily oiled, whereas adjacent areas facing west or south received little oil. The best studied example is at the northwestern side of Isla Largo Remo (Table 2).
21. These low tides occur annually at this time of year (*8, 9*). Sea levels during most of this time were as much as 10 cm below the 9-year average for this period of normally low sea level.
22. Corals were collected by divers on days when no surface slicks were visible, placed in solvent-rinsed aluminum foil, and frozen. Tissues were removed from skeletons with an air pick and homogenized with a tissue grinder. To minimize variations due to water or carbonate inclusions, standard Lowrey protein determinations were used as one measure of tissue mass. After solvent extraction, total lipid weights were determined macrogravimetrically. Extracts were fractionated by adsorption chromatography. Hydrocarbons were analyzed with a capillary gas chromatograph equipped with a flame ionization detector and 25-m SE 52 fused silica columns.
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25. This estimate was extrapolated from aerial photographs of 36 km of the 82-km shoreline, of which 76 km contains mangroves. Of the photographed shoreline, 36% contained a band of dead mangroves.
26. Sprouting success was measured for seedlings collected from an unoiled site, and planted in one unoiled and two oiled sites. Of 25 seedlings transplanted into each site, 16 (64%) sprouted at the unoiled site and 1 (2%) sprouted at the oiled sites.
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28. Roots were sampled three times before the spill in rivers and channels (September to October 1981, January 1982, and June 1982) and twice in open habitats (September to October 1981 and January 1982). Several areas of shore within each habitat were chosen haphazardly. Fifteen to 25 intertidal roots ≥20 cm long that had not become firmly attached to the mud were lifted from the water, and cover of attached organisms was measured for each root by 100 random point counts after the oil spill or was estimated visually before the spill. After the spill, previously sampled riverine and channel habitats included both oiled and unoiled sites but all open sites were oiled. Thus it was necessary to choose sites near Portobelo (Fig. 2),

the nearest equivalent unoiled shoreline, for unoiled open habitat similar to oiled open habitat. One hundred roots were sampled in each oiled and unoiled habitat after the spill.

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30. All seagrass beds sampled lie adjacent to mangrove shoreline and are ≥1 m deep; unoiled beds meeting these criteria occur near Portobelo and Isla Grande (Fig. 2). Infauna were collected with 10.2-cm inside diameter polyvinyl chloride (PVC) tubes pushed into the sediment to a depth of at least 10 cm. Each sample consists of three pooled cores (240 cm^2). At each census eight samples were collected haphazardly at each site. Samples were sieved over 500-μm mesh and preserved in 10% formalin with rose bengal. Animals were sorted to major taxa and counted or weighed wet.
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33. Percent cover of sessile species attached to the substratum was estimated by point sampling along ten permanent transects 9 to 22 m long, perpendicular to the reef edge and spaced at random intervals within a 20-m strata. The number of points sampled per survey was between 1510 and 1560. The seaward 6 m of these transects were more directly exposed to oil than the landward portions. This 6-m band forms the "heavily oiled zone" of Fig. 6. Sea urchins were counted in two 1 × 20 m transects; one at the reef edge, the other 26 m farther landward.
34. For the reef edge transect only, residuals from regressions of changes in abundance from May to June were highly negative in 1986 compared with all other transects in all other years ($n = 41$, $r^2 = 0.88$, $P < 0.001$).
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37. The four collection sites ranged from 100 to 125 m × 25 to 40 m (all larger than 3000 m^2) and were selected before the spill to have intertidal *Thalassia* beds with firm, sandy substratum, and moderate amounts of rubble and coralline algal nodules. Densities of stomatopods were estimated from 30 quadrats (0.5 m^2) chosen at random within 400-m^2 plots at each site. All hard substrata were removed from each quadrat and broken, and all stomatopods were retained. A minimum of 300 individuals was collected, including ones from pieces of coral rubble collected haphazardly within each site, but outside the plot used for quadrats. These animals were included in the analysis of injuries and growth.
38. Cuticular injuries were recorded for all animals as described by I. K. Berzins and R. L. Caldwell [*Mar. Behav. Physiol.* 10, 83 (1983)].
39. We estimated growth by comparing the length of the carapace of animals newly molted in the laboratory with its length before molting, using only animals that molted within 3 days of capture and were longer than 35 mm.
40. Almost every piece of rubble in the heavily oiled plots was covered by hundreds of hermit crabs. Such densities were not observed in unoiled plots or in any years previously.
41. See P. W. Glynn [*Bull. Biol. Soc. Wash.* 2, 13 (1972)] and J. W. Porter (*ibid.*, p. 89) for general descriptions of Panamanian reefs. We selected fringing reefs that extended at least 100 m along the shoreline and to a depth of at least 12 m. At each reef four or five line transects were extended from haphazardly chosen points at the shoreward edge of the reef to the deepest point of the reef. Along each line, 1-m^2 quadrats were placed contiguously or up to 3 m apart, depending on transect length (8 to 81 quadrats per transect). Quadrats were divided into 100-cm^2 cells, and total cover was estimated by eye within each cell.
42. We determined differences in coral cover before and after the spill (July to October 1985 and July to August 1986) by combining all quadrats at each of three depths (0 to 3, 3 to 6, and 6 to 12 m; prespill $n = 306$, 219, and 135 quadrats, respectively; postspill $n = 294$, 200, and 187) at each site and then calculating ln (mean cover before the spill/mean cover afterward). The effect of oil was examined by one-way analysis of variance of these values for one heavily oiled, one lightly oiled, and four unoiled reefs; df = 2. For 0 to 3 m depth, $F = 13.3$, $P = 0.032$; 3 to 6 m, $F = 4.48$; $P = 0.13$; 6 to 12 m, $F = 0.90$, $P = 0.49$.
43. Dead areas were bare or colonized by thin growth of filamentous algae. Ten such colonies of *S. siderea* were sealed in plastic bags underwater, brought to the laboratory, and placed in clean tanks and seawater. A film of oil appeared on the surface of each tank when the filamentous algae growing over the recently dead areas were squeezed by hand.
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45. Recent injuries were counted on 12 reefs for all corals in 2 × 50 m transects haphazardly located at 0 to 1 m and 1 to 2 m depth. Injuries were counted only when the exposed skeleton was bare or only lightly overgrown by filamentous algae. Size of injury was visually estimated as percent of the total surface area of each coral.
46. Significance was tested with hierarchical log-linear models (SPSS/PC+, 1987) with the following variables: coral species (three levels), water depth (two levels), amount of injury (three levels), and amount of oiling (three levels). Injuries were not distributed equally as a function of amount of oiling for any of the three coral species ($P < 0.001$); injuries increased in frequency and severity as amount of oiling increased among sites. The effect of oiling on coral injuries was not independent of depth ($P < 0.001$); injuries were more frequent at shallower depths. The three coral species differed in frequency of injuries ($P < 0.001$), with *S. siderea* > *Porites astreoides* > *Diploria clivosa*. In April 1987, about 1 year after the oil spill, coral injuries were still not distributed equally as a function of amount of oiling among sites ($P < 0.001$).
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